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Presidential Documents

Title 3—

The President

Memorandum of December 30, 1992

Prescription of the Conditions Under Which Commissioned Officers of the Public Health Service May Be Awarded Military Ribbons, Medals, and Decorations

Memorandum for the Secretary of Defense, the Secretary of Health and Human Services

The authority of the President under section 212(b) of the Public Health Service Act (42 U.S.C. 213(b)) is hereby delegated to the Secretary of Defense. In the exercise of that authority, the Secretary of Defense shall ensure that no military ribbon, medal, or decoration is awarded to an officer of the Public Health Service without the approval of the Secretary of Health and Human Services.

The Secretary of Defense shall ensure the publication of this memorandum in the **Federal Register**.

George Bush

THE WHITE HOUSE,
Washington, December 30, 1992.

[FR Doc. 93–617
Filed 1–7–93; 3:21 pm]
Billing code 3195–01–M

Rules and Regulations

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This section of the FEDERAL REGISTER contains regulatory documents having general applicability and legal effect, most of which are keyed to and codified in the Code of Federal Regulations, which is published under 50 titles pursuant to 44 U.S.C. 1510.

The Code of Federal Regulations is sold by the Superintendent of Documents. Prices of new books are listed in the first FEDERAL REGISTER issue of each week.

DEPARTMENT OF JUSTICE

Immigration and Naturalization Service

8 CFR Part 100

[INS No. 1349–92]

RIN 1115–AC95

Statement of Organization; Name Change for Border Patrol Sector Number 3

AGENCY: Immigration and Naturalization Service, Justice.

ACTION: Final rule.

SUMMARY: This rule amends 8 CFR 100.4 by changing the name of sector headquarters number 3 from "Mayaguez, Puerto Rico" to "Ramey, Puerto Rico". This change is necessary to avoid confusion, since sector number 3 is physically located in Ramey, Puerto Rico.

EFFECTIVE DATE: January 11, 1993.

FOR FURTHER INFORMATION CONTACT: Marion E. Moody, Assistant Chief Patrol Agent, Border Patrol, Immigration and Naturalization Service, 425 I Street, NW., room 7227, Washington, DC 20536, telephone (202) 514–1109.

SUPPLEMENTARY INFORMATION: Originally the Immigration and Naturalization Service intended to install a Sector Headquarters and station in Mayaguez, Puerto Rico, along with maintaining a station in Ramey, Puerto Rico. As a result of budget constraints and lack of suitable space, the Service no longer plans to open a Sector office in Mayaguez. Therefore 8 CFR 100.4 is being amended to change the name of sector headquarters number 3 from "Mayaguez, Puerto Rico" to "Ramey, Puerto Rico", since the sector number 3 headquarters is physically located in Ramey, Puerto Rico.

The Service's implementation of this rule as a final rule is based upon 5 U.S.C. 553(b)(A) as it is a rule of agency organization. The immediate implementation of this final rule is based upon the "good cause" exception found at 5 U.S.C. 553(d) in that the usual notice provisions are unnecessary because the rule will benefit the public by showing the actual city in which the sector headquarters is physically located.

In accordance with 5 U.S.C. 605(b), the Commissioner of the Immigration and Naturalization Service certifies that this rule does not have a significant adverse economic impact on a substantial number of small entities. This rule is not considered to be a major rule within the meaning of section 1(b) of E.O. 12291, nor does this rule have Federalism implications warranting the preparation of a Federalism Assessment in accordance with E.O. 12612.

List of Subjects in 8 CFR Part 100

Authority delegation (Government agencies), Organization and functions (Government agencies).

Accordingly, part 100 of chapter I of title 8 of the Code of Federal Regulations is amended as follows:

PART 100—STATEMENT OF ORGANIZATION

1. The authority citation for part 100 continues to read as follows:

Authority: 8 U.S.C. 1103; 8 CFR part 2.

§ 100.4 [Amended]

2. In section 100.4, paragraph (d) is amended by changing the name of Sector number 3 from "Mayaguez, Puerto Rico", to "Ramey, Puerto Rico".

Dated: December 9, 1992.

Gene McNary,

Commissioner, Immigration and Naturalization Service.

[FR Doc. 93–461 Filed 1–8–93; 8:45 am]

BILLING CODE 4410–10–M

FEDERAL HOUSING FINANCE BOARD

12 CFR Part 932

[No. 92–749]

Eligibility of Federal Home Loan Bank Directors

AGENCY: Federal Housing Finance Board.

ACTION: Interim rule.

SUMMARY: The Federal Housing Finance Board (Board) is amending its regulations to revise the dates by which all incumbent directors of the Federal Home Loan Banks (FHLBanks) must submit Personal Certification and Disclosure forms to the Board. The amendments also clarify the date by which nominees for elective director must submit Personal Certification and Disclosure forms to the Board. The amendments also change the date by which the Board must announce the results of the election for FHLBank directors. These date changes are intended to apportion the submission of forms over a longer period in order to enable the Board to devote more time to the review of the forms. The amendments also define more precisely the period during which a director or officer of a member of the FHLBank System who was formerly ineligible to be a FHLBank elective director may once again be eligible to hold that office.

DATES: Interim rule effective on January 11, 1993. Comments must be received on or before March 12, 1993.

ADDRESSES: Comments may be mailed to: Executive Secretariat, Federal Housing Finance Board, 1777 F Street, NW., Washington, DC 20006. Comments will be available for public inspection at this address.

FOR FURTHER INFORMATION CONTACT: Patricia L. Sweeney, Program Analyst, District Banks Directorate, (202) 408–2872; Brandon Straus, Attorney-Advisor, Office of Legal and External Affairs, (202) 408–2589, Federal Housing Finance Board, 1777 F Street, NW., Washington, DC 20006.

SUPPLEMENTARY INFORMATION:

I. Statutory and Regulatory Background

Section 7 of the Federal Home Loan Bank Act (Bank Act), 12 U.S.C. 1421 *et seq.* (Supp. I 1989), vests the management of each FHLBank in a board of elective and appointive directors. *Id.* sec. 1427(a). Bank Act subsection 7(d) authorizes the Board to prescribe rules for the nomination and election of elective FHLBank directors. *Id.* sec. 1427(d). The Board has authority to prescribe rules governing the appointment of appointive FHLBank directors pursuant to its general rulemaking authority in Bank Act subsection 2B(a). See *id.* sec. 1422b(a)(1).

The current Board regulations on appointive director eligibility and elective director eligibility set forth dates by which incumbent directors, nominees for elective director (director nominees), and candidates for appointive director (director candidates) must submit to the Board a certification that they meet certain statutory and regulatory eligibility requirements as well as a statement of disclosure of certain financial relationships. See 12 CFR 932.18(f), 932.21(g). These certifications and disclosures must be made by completing Personal Certification and Disclosure Forms (Forms), denominated A–1, A–2, E–1, or E–2. These forms have been approved by the Office of Management and Budget (OMB) and have been assigned OMB control number 3069–0002. Satisfactory completion of the Forms is a prerequisite for incumbent elective and appointive directors to remain eligible to serve on a FHLBank board. Satisfactory completion of the Forms is also a prerequisite to the ratification of the election of director nominees and the appointment of director candidates by the Board.

Under the current regulations, incumbent appointive directors must submit their Forms annually by November 15, and incumbent elective directors must do by December 1. However, during the months of October through December, the Board also must review Forms submitted by director candidates and director nominees. Director candidates are required to submit their Forms "[p]rior to the initial appointment." *Id.* § 932.18(f). Most director appointments are made near the end of the year because the four year terms of appointive directors expire on December 31. However, some appointments are made other than at year end in order to fill appointive directorships that have been vacated at mid-term.

Director nominees must submit their Forms "[p]rior to each election." *Id.* § 932.21(g). The process of election of director nominees takes place from September 25 to October 25 of each year. *Id.* § 932.14(a), (c). The Board must announce the results of the election by November 15. *Id.* § 932.14(d). As a result of this series of deadlines set forth in the current regulations, the Board is required to review the incoming Forms of approximately 110 incumbent directors while at the same time reviewing Forms from up to sixty director nominees in time for the Board to ratify the election of those nominees by November 15.

II. Analysis of Interim Rule

A New Date For Submission of Personal Certification and Disclosure Forms by Incumbent Directors

In order to allow the Board more time to review the Forms of director candidates and director nominees, which are submitted to the Board in the final months of the calendar year, the Board is amending § 932.18 and § 932.21 of its regulations to provide that incumbent elective and appointive directors must submit Forms E–2 and A–2, respectively, annually by March 1. This change is intended to apportion the submission of Forms over a longer period so that the Board has more time to review individual Forms.

In order to avoid duplicative certification and disclosure requirements for certain new directors, the interim rule creates some exceptions to the requirements for submission of Forms E–2 and A–2. Newly elected elective directors, who were required to submit a Form E–1 in the year in which they were elected, would be exempt from submitting a Form E–2 in the following year. Similarly, appointive directors who submitted a Form A–1 in October, November, or December of the year prior to the year in which their appointment took effect would be exempt from submitting a Form A–2 by March 1 of the following year.

As a consequence of these exceptions, newly elected directors will not be required to submit Forms for up to a fifteen month period: from late October of the year in which they were elected to March 1 of the second year of their terms. In addition, appointive directors who submitted Form A–1 in October, November, or December of the year prior to the year in which their appointment took effect will not be required to submit a Form for up to a seventeen month period: from October 1 of the year prior to the year in which their appointment was effective to March 1 of the second year of their terms.

The Board believes that allowing first-year directors to serve several added months before they are required to meet the certification and disclosure requirements as incumbent directors poses minimal risk to the FHLBanks and the FHLBank System because all incumbent directors are required by regulation to report, on their own initiative, any ineligibility or suspected ineligibility to the Board within thirty days of occurrence. *See id.* §§ 932.18(f)(2), 932.21(g)(2).

B New Dates for Submission of Personal Certification and Disclosure Forms By Elective Director Nominees

The current regulation governing the nomination of director nominees requires each director nominee to complete a "questionnaire" and return it to the Board prior to August 20 in order for the director nominee's name to be placed on the ballot for the next election. *Id.* § 932.13(c)(3). In practice, the Board now requires that director nominees fill out and return to the Board by August 20 that portion of Form E–1 in which director nominees certify that they meet all statutory and regulatory eligibility requirements for election. The Board no longer uses a "questionnaire." Therefore, the interim rule changes the language of § 932.13(c)(3) to reflect this practice.

The current elective director eligibility regulations require that "[p]rior to each election," director nominees must certify in Form E–1 that they meet certain statutory and regulatory eligibility requirements and must disclose to the Board certain financial relationships. See *id.* § 932.21(g)(1), (3). However, it is the current Board practice to wait until after the ballots have been opened to require those director nominees with the highest number of votes for each directorship to complete a Form E–1. The Board must, by regulation, wait until 5 p.m. on October 25 before opening ballots. *Id.* § 932.14(c). The reason for this practice is that the Board wishes to require disclosure of personal financial relationships only by director nominees whose election has some likelihood of being ratified by the Board

The interim rule therefore replaces the phrase "[p]rior to each election" in subparagraphs (g)(1) and (g)(3) of § 932.21 with "[p]rior to the ratification of the election results by the Board." This change is intended to make clear that director nominees are not required to disclose their financial relationships to the Board on Form E–1 until after members cast their ballots and after the results are tabulated. See *id.* § 932 14(c). However, director nominees must submit the completed Form E-l before the Board will ratify their election and declare the election results. The change made by the interim rule is intended to reflect this practice.

The Board recognizes that those director nominees who must fill out Form E–1 prior to ratification of their election by the Board will have filled out the certification section of Form E–1 twice: once by August 20 in order to have his or her name placed on the ballot and again after the election when

disclosing his or her financial relationships. The purpose of requiring director nominees to again certify eligibility after the election is to ensure that director nominees are still eligible to be FHLBank directors at the time the Board ratifies their election. Further, by certifying their eligibility after they are elected, director nominees are exempted from submitting a Form E–2 during the following year.

C New Date for Declaration of Election Results

The current Board regulation governing the election of FHLBank elective directors provides that the Board will determine and announce the winners of the election by November 15, *Id.* § 932.14(d). However, director nominees are not required to complete Form E–1 until after they have been elected. Therefore, the November 15 date allows only three weeks for director nominees to submit their Forms and for the Board to review the Forms before the election results must be announced. Section 932.14(c) of the interim rule changes the announcement date to December 31. This change is intended to ensure that the Board will have sufficient time to review Forms of director nominees and ratify their election, should director nominees wait until mid- or late December to submit their Forms. The Board does not intend to delay the announcement of election results until December 31, if the Board can ratify the results prior to that date.

D Clarification of Eligibility Requirement For Elective Directors Whose Institution Fails To Meet Its Capital Requirements

The Board is also amending the regulation governing eligibility of a person who was formerly ineligible to be an elective director due to non-compliance with minimum regulatory capital requirements by the member institution that the person serves as an officer or director. See id. § 932.21(d)(2). The current regulation provides that a "director" who was formerly ineligible is once again eligible in the succeeding calendar year if the member meets the minimum regulatory capital requirements during each phase of the election process for the succeeding calendar year. *Id.*

The interim rule clarifies the regulation by expressly making it applicable to a "person" who was formerly ineligible rather than a "director" who was formerly ineligible. This change is intended to clarify the Board's intent and to reflect current Board practice of applying the regulation not only to incumbent elective directors but also to director nominees and prospective director nominees. This change is also intended to make the regulation's language parallel the language of paragraph (d)(1) of § 932.21, which defines the period during which a "person" who is an officer or director of a member that fails to meet minimum regulatory capital requirements is ineligible to be an elective director. *Id.* § 932.21(d)(1).

The interim rule further amends the regulation governing re-eligibility by rephrasing the time frame during which a member must meet minimum regulatory capital requirements in order for a formerly ineligible person to once again be eligible to be an elective director. The interim rule does not change the time frame, but it defines the time frame in terms of the calendar year rather than in terms of a "phase of the election process."

III. Notice and Public Participation

A. General Notice of Proposed Rulemaking

The Board is requesting public comment on this interim rule, although it is not required by the Administrative Procedure Act (APA), 5 U.S.C. 551 *et seq.*, to publish a general notice of proposed rulemaking. Publication of notice of a proposed rulemaking is not required because the Board finds that there is good cause that notice and comment procedure is unnecessary and contrary to the public interest in this instance. See *id.* sec. 553(b)(3)(B). Compliance with the public procedure requirements of APA section 553 is unnecessary because the interim rule makes minor technical amendments to the director eligibility regulations. The amendments do not impose any new substantive requirements on FHLBank directors and therefore do not involve matters of public interest or concern.

Implementation of the interim rule without prior public notice will not create a hardship for those people who are subject to the rule. The deadlines set forth in the new rule will allow incumbent directors an extra three months in which to comply with the certification and disclosure requirements. Director nominees will also have more time to comply with the certification and disclosure requirements because the interim rule makes clear that the deadline for submission of their Forms is no longer prior to the election, but prior to ratification of the election results by the Board, which takes place after the election. Public notice and comment is therefore unnecessary in the promulgation of the interim rule.

Although the content of the interim rule does not involve matters of the public interest, delaying the effect of the interim rule would be contrary to the public interest. The deadline changes in the interim rule allow the Board more time in which to review the Forms of FHLBank directors during the election process. It is in the public interest for the Board to have more time in which to review the qualifications of FHLBank directors because the safe and efficient operation of the FHLBank System is dependent upon the selection of qualified FHLBank directors. Delaying the effect of the interim rule in order to follow the notice and comment procedures would cause the rule to become effective after the deadlines that are changed by the rule have passed. This would deprive the Board of the benefit of the rule in the current election cycle. Therefore, delaying implementation of the interim rule would be contrary to the public interest.

The Board therefore finds good cause that compliance with notice and comment procedures in adoption of this interim rule is unnecessary and contrary to the public interest. Further, the interim rule comes within the exception to the notice and comment requirement for rules of agency procedure, under section 553(b)(3)(A) of the APA. See *id.* section 553(b)(3)(A).

B. Effective Date

The Board finds that section 553(d) of the APA, which generally requires publication of a substantive rule at least thirty days before the rule's effective date, is not applicable to this interim rule. The interim rule makes changes in the Board's procedure for accepting certification and disclosure Forms from FHLBank directors. The interim rule is not a substantive rule because it does not change any of the substantive requirements for director eligibility. Therefore, the requirement of a thirty-day delay in the effective date of a substantive rule does not apply to this interim rule, which is procedural.

The Board also finds that under APA subsection 553(d)(3), there is good cause that the interim rule be effective upon publication for the reasons stated in section III.A.

Although this interim rule is effective immediately, the Board requests public comment. The Board considers comments from the public helpful in formulating clear and effective regulations. Therefore, the Board will consider public comments on this interim rule in developing a final rule.

IV. Regulatory Flexibility Act

The Board is not required by the Regulatory Flexibility Act (Reg Flex Act), 5 U.S.C. 601 *et seq.*, to prepare a regulatory flexibility analysis for this interim rule. The Reg Flex Act requires that a regulatory flexibility analysis be prepared whenever an agency promulgates a proposed or final rule after being required by the APA to publish a general notice of proposed rulemaking pursuant to section 553 of the APA. See 5 U.S.C. 603(a), 604(a). The Board is not required to publish a general notice of proposed rulemaking for this interim rule because the Board has found good cause that notice and comment is unnecessary and contrary to the public interest in the adoption of this interim rule. See *id.* sec. 553(b)(3)(B). Further, the rule comes within the exception to the notice and comment requirement for rules of agency procedure, under APA subsection 553(b)(3)(A). See *id.* sec. 553(b)(3)(A).

The interim rule does not impose any new reporting requirements. It merely changes the deadlines by which existing requirements must be met. The interim rule therefore will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 12 CFR Part 932

Banks, Banking, Conflicts of interest, Elections, Ethical conduct, Federal home loan banks, Financial disclosure, Reporting and recordkeeping requirements.

Accordingly, chapter IX, title 12, part 932, Code of Federal Regulations, is hereby amended as follows:

PART 932—ORGANIZATION OF THE BANKS

1. The authority citation for part 932 is revised to read as follows:

Authority: 12 U.S.C. 1422a, 1422b, 1426, 1427, 1464; 18 U.S.C. 207; 42 U.S.C. 8101 *et seq.*

2. Section 932.13 is amended by revising the first two sentences of paragraph (c) concluding text to read as follows:

§ 932.13 Designation and nomination of elective directorship.

* * * * *

(c) * * *

With such letter will be sent a list of nominees and a copy of Form E–1. Each nominee must certify to the Board on Form E–1 by August 20 that such nominee meets all applicable eligibility qualifications for his election set forth in section 7 of the Act and this part.

* * *

* * * * *

3. Section 932.14 is amended by revising the first sentence of paragraph (d) to read as follows:

§ 932.14 Election of directors.

* * * * *

(d) By December 31, the Board will declare elected the candidate receiving the highest number of votes cast, and where two or more directorships are to be filled from the ballot, the Board will declare elected each candidate receiving the next succeeding highest number of votes until the number of candidates declared elected equals the number of directorships to be filled. * * *

* * * * *

4. Section 932.18 is amended by revising paragraphs (f)(1) and (f)(3) introductory text to read as follows:

§ 932.18 Appointive director eligibility.

* * * * *

(f) *Certification and reporting.* (1) Prior to the initial appointment, each director candidate for appointive director shall certify in writing to the Board on Form A–1 that he or she meets all applicable eligibility qualifications for his or her appointment set forth in section 7(a) of the Act and this part. By March 1 of each year during the term of the directorship, each appointive director shall certify in writing to the Board on Form A–2 that he or she meets all applicable eligibility qualifications for his or her appointment set forth in section 7(a) of the Act and this part, except that any appointive director who submitted Form A–1 to the Board in October, November, or December of the year prior to the year in which his or her appointment took effect is not required to submit Form A–2 by March 1 of the year in which the appointment took effect.

* * * * *

(3) Prior to the initial appointment, each director candidate for appointive director shall fully disclose in writing to the Board on Form A–1 the financial relationships (as defined in § 931.30 of this chapter) set forth in paragraphs (f)(3) (i), (ii), (iii), and (iv) of this section of such director candidate. By March 1 of each year during the term of directorship, each appointive director shall fully disclose in writing to the Board on Form A–2 the financial relationships (as defined in § 931.30 of this chapter) set forth in paragraphs (f)(3) (i), (ii), (iii), and (iv) of this section of such appointive director, except that any appointive director who submitted a Form A–1 to the Board in October, November, or December of the year prior to the year in which his or her appointment took effect is not required to submit Form A–2 by March 1 of the year in which the appointment took effect.

* * * * *

5. Section 932.21 is amended by revising paragraphs (d)(2), (g)(1), and (g)(3) to read as follows:

§ 932.21 Elective director eligibility.

* * * * *

(d) * * *

(2) A person who is ineligible pursuant to paragraph (d)(1) of this section shall once again be eligible for election in the next succeeding calendar year in which the member(s) he or she serves as an officer or director meet(s) the applicable minimum regulatory capital requirements throughout the entire calendar year. Such compliance with applicable minimum regulatory capital requirements shall not be satisfied by the granting of an exemption or exception to such capital requirements by the appropriate federal regulatory agency.

* * * * *

(g) *Certification and reporting.* (1) Prior to the ratification of the election results by the Board, each director nominee for elective director shall certify in writing to the Board on Form E–1 that he or she meets all applicable eligibility qualifications for his or her election set forth in section 7 of the Act and this part. By March 1 of each year during the term of directorship, each elective director who was not elected in the immediately preceding year shall certify in writing to the Board on Form E–2 that he or she meets all applicable eligibility qualifications for his or her election set forth in section 7 of the Act and this part.

* * * * *

(3) Prior to the ratification of the election results by the Board, each director nominee for elective director shall fully disclose in writing to the Board on Form E–1, and by March 1 of each year thereafter during the term of the directorship each elective director who was not elected in the immediately preceding year shall fully disclose in writing to the Board on Form E–2, any financial relationships (as defined in § 931.30 of this chapter) set forth in § 932.18(f)(3) of this part of such director nominee or elective director.

* * * * *

By the Federal Housing Finance Board

Daniel F. Evans, Jr.,

Chairman.

[FR Doc. 93–537 Filed 1–8–93; 8:45 am]

BILLING CODE 6725-01-M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 92–ANE–61; Amendment 39–8445]

Airworthiness Directives; Garrett Engine Division, Allied-Signal Incorporated, Model TFE731–5BR Turbofan Engines

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule, request for comments.

SUMMARY: This document publishes in the **Federal Register** an amendment adopting Airworthiness Directive (AD) priority letter 92–02–18 that was sent previously to all known U.S. owners and operators of Garrett Engine Division, Allied-Signal Incorporated, Model TFE731–5BR turbofan engines by individual letters. This AD requires discontinuation of inflight operation of certain engines. This amendment is prompted by two reports of inflight shutdowns due to fan gearbox failures. The actions specified by this AD are intended to prevent multiple inflight engine failures.

DATES: Effective February 10, 1993, to all persons except those persons to whom it was made immediately effective by priority letter AD 92–02–18, issued January 14, 1992, which contained the requirements of this amendment.

Comments for inclusion in the Rules Docket must be received on or before February 10, 1993.

ADDRESSES: Submit comments in triplicate to the Federal Aviation Administration (FAA), New England Region, Office of the Assistant Chief Counsel, Attention: Rules Docket No. 92–ANE–61, 12 New England Executive Park, Burlington, Massachusetts 01803–5299.

FOR FURTHER INFORMATION CONTACT: Joseph Costa, Propulsion Branch, ANM–140L, Los Angeles Aircraft Certification Office, Transport Airplane Directorate, Aircraft Certification Service, FAA, 3229 East Spring Street, Long Beach, California, 90806–2425; telephone (310) 988–5246; fax (310) 988–5210.

SUPPLEMENTARY INFORMATION: On January 14, 1992, the FAA issued priority letter AD 92–02–18, applicable to Garrett Engine Division, Allied-Signal Incorporated, Model TFE731 series turbofan engines, which requires discontinuation of inflight operation of certain engines. That action was prompted by reports of two recent inflight engine shutdowns due to fan gearbox failures that occurred within 8 hours time in service following conversion of the engines from Garrett Model TFE731–5AR to Garrett Model TFE731–5BR engines. Preliminary investigation has revealed fatigue cracks originating from the aft damper ring groove of the sun gear. These cracks progressed until the gear cracked along the gear tooth root, which caused a vibration and fragmentation of the sun gear. This condition, if not corrected, could result in multiple inflight engine failures.

Since the unsafe condition described is likely to exist or develop on other engines of the same type design, the FAA issued priority letter AD 92–08–18 to prevent multiple inflight engine failures. The AD requires discontinuation of further flight of certain engines.

Since it was found that immediate corrective action was required, notice and opportunity for prior public comment thereon were impracticable and contrary to the public interest, and good cause existed to make the AD effective immediately by individual letters issued on January 14, 1992, to all known U.S. owners and operators of Garrett Engine Division, Allied-Signal Incorporated, Model TFE731–5BR turbofan engines. These conditions still exist, and the AD is hereby published in the **Federal Register** as an amendment to § 39.13 of part 39 of the Federal Aviation Regulations (FAR) to make it effective as to all persons.

Comments Invited

Although this action is in the form of a final rule that involves requirements affecting flight safety and, thus, was not preceded by notice and an opportunity for public comment, comments are invited on this rule. Interested persons are invited to comment on this rule by submitting such written data, views, or arguments as they may desire. Communications should identify the Rules Docket number and be submitted in triplicate to the address specified under the caption "**ADDRESSES.**" All communications received on or before the closing date for comments will be considered, and this rule may be amended in light of the comments received. Factual information that supports the commenter's ideas and suggestions is extremely helpful in evaluating the effectiveness of the AD action and determining whether additional rulemaking action would be needed.

Comments are specifically invited on the overall regulatory, economic, environmental, and energy aspects of the rule that might suggest a need to modify the rule. All comments submitted will be available, both before and after the closing date for comments, in the Rules Docket for examination by interested persons. A report that summarizes each FAA-public contact concerned with the substance of this AD will be filed in the Rules Docket.

Commenters wishing the FAA to acknowledge receipt of their comments submitted in response to this notice must submit a self-addressed, stamped postcard on which the following statement is made: "Comments to Docket Number 92–ANE–61." The postcard will be date stamped and returned to the commenter.

The regulations adopted herein will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612, it is determined that this final rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

The FAA has determined that this regulation is an emergency regulation and that it is not considered to be major under Executive Order 12291. It is impracticable for the agency to follow the procedures of Order 12291 with respect to this rule since the rule must be issued immediately to correct an unsafe condition in aircraft. It has been determined further that this action involves an emergency regulation under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979). If it is determined that this emergency regulation otherwise would be significant under DOT Regulatory Policies and Procedures, a final regulatory evaluation will be prepared and placed in the Rules Docket. A copy of it, if filed, may be obtained from the Rules docket at the location provided under the caption "**ADDRESSES.**"

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends 14 CFR part 39 of the Federal Aviation Regulations as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. App. 1354(a), 1421 and 1423; 49 U.S.C. 106(g); and 14 CFR 11.89.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive:

92–02–18: Garrett Engine Division, Allied-Signal Incorporated: Amendment 39–8445. Docket No. 92–ANE–61.

Applicability: Garrett Engine Division, Allied-Signal Incorporated, Model TFE731–5BR turbofan engines installed on but not limited to Dassault Aviation Model Mystere Falcon 20 and 900 series airplanes.

Compliance: Required prior to further flight, unless accomplished previously.

To prevent multiple inflight engine failures, accomplish the following:

(a) For engines identified on the data plate as Part Number (P/N) 3075330–2 or P/N 3075370–1, discontinue inflight operation.

(b) This AD is an interim directive until approved corrective action is available.

(c) An alternative method of compliance or adjustment of the compliance time that provides an acceptable level of safety may be used if approved by the Manager, Los Angeles Aircraft Certification Office. The request should be forwarded through an appropriate FAA Maintenance Inspector, who may add comments and then send it to the Manager, Los Angeles Certification Office.

Note: Information concerning the existence of approved alternative methods of compliance with this airworthiness directive, if any, may be obtained from the Los Angeles ACO.

(d) Special flight permits may be issued in accordance with FAR 21.197 and 21.199 to operate the airplane to a location where the requirements of this AD can be accomplished.

(e) This amendment becomes effective on February 10, 1993, to all persons except those persons to whom it was made immediately effective by priority letter AD 92–02–18, issued January 14, 1992, which contained the requirements of this amendment.

Issued in Burlington, Massachusetts, on December 16, 1992.

Jay J. Pardee,

Acting Manager, Engine and Propeller Directorate, Aircraft Certification Service.

[FR Doc. 93–476 Filed 1–8–93; 8:45 am]

BILLING CODE 4910–13–M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[MA–09–01–5383; A–1–FRL–4538–7]

Approval and Promulgation of Air Quality Implementation Plans; Massachusetts; Revised Regulations Controlling Volatile Organic Compound Emissions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is approving portions of the State Implementation Plan (SIP) revisions submitted by the Commonwealth of Massachusetts which amend its volatile organic compound (VOC) regulations. The intended effect of this action is to approve portions of the Massachusetts revised SIP for ozone. This action is being taken in accordance with section 110 and part D of the Clean Air Act (CAA).

EFFECTIVE DATE: This rule will become effective on February 10, 1993.

ADDRESSES: Copies of the documents relevant to this action are available for public inspection during normal business hours, by appointment at the Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region I, One Congress Street, 10th floor, Boston, MA; Public Information Reference Unit, U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460; and Department of Environmental Protection, One Winter Street, 7th Floor, Boston, MA 02108.

FOR FURTHER INFORMATION CONTACT: Emanuel Souza, Jr., (617) 565–3248.

SUPPLEMENTARY INFORMATION: On February 3, 1983 (48 FR 5044), June 1, 1987 (52 FR 20422) and May 29, 1990 (55 FR 21755), EPA published Notices of Proposed Rulemakings (NPR) for the Commonwealth of Massachusetts. The February 3, 1983 NPR proposed approval of Massachusetts' 1982 SIP. The June 1, 1987 NPR proposed approval of Massachusetts' generic bubble regulations, 310 CMR 7.18(2)(b) and 310 CMR 7.00: Appendix B. EPA's May 29, 1990 NPR proposed approval of an August 17, 1989 SIP revision of VOC regulations. Massachusetts submitted the formal SIP revisions on August 27, 1982, June 27, 1984, March 6, 1985, April 12, 1985, August 17, 1989 and June 7, 1991. Additionally, the state submitted a letter on December 17, 1991 withdrawing portions of the June 7, 1991 submittal because of typographical errors.

Background

On August 27, 1982, Massachusetts submitted its 1982 SIP to EPA for approval. On February 3, 1983, EPA published an NPR for Massachusetts' 1982 SIP. However, in the final rulemaking notice for Massachusetts' 1982 SIP (48 FR 51480), EPA stated that all the issues regarding the bubble regulations (310 CMR 7.18(2)(b) and 310 CMR 7.00: Appendix B) were not resolved, and that, EPA would take final action on the two bubble regulations at a later date.

On June 27, 1984, March 6, 1985 and April 12, 1985, Massachusetts submitted revisions to its generic bubble regulations, 310 CMR 7.18(2)(b) and 310 CMR 7.00: Appendix B to EPA for approval. On June 1, 1987, EPA published an NPR for Massachusetts' generic bubble regulations. In that notice EPA listed 14 conditions that Massachusetts had to satisfy before EPA would take final action on these regulations.

On May 25, 1988, EPA sent a letter to the Governor of Massachusetts notifying him that the Massachusetts SIP was substantially inadequate to achieve the National Ambient Air Quality Standard (NAAQS) for ozone in the entire State. EPA requested the State to respond to that letter in two phases—the first in the near future and the second following EPA's issuance of a final policy on how the States should correct their SIPs. One of the requirements of the first phase of the State's response was to correct the deficiencies identified by EPA in the existing SIP's VOC regulations.

On June 16, 1988, EPA sent a letter to the Acting Director of the Massachusetts Department of Environmental Protection (DEP) Division of Air Quality Control outlining the corrections that needed to be made to Massachusetts' existing regulations in order to eliminate the identified deficiencies and inconsistencies in the regulations as compared to EPA's national guidance.

The Commonwealth of Massachusetts made changes to its VOC regulations as required by EPA's May 25 and June 16, 1988 letters, and submitted the revised adopted VOC regulations as a formal SIP revision on August 17, 1989.

EPA proposed approval of the August 17, 1989 submittal in two notices. The automobile surface coating regulation was published separately as a proposed partial disapproval and proposed partial approval. This notice was published in the **Federal Register** on October 12, 1990 (55 FR 41553). EPA acted on the automobile surface coating regulation separately because a portion of the submittal, the compliance dates for the

topcoat and final repair applications, had already been disapproved by EPA on September 16, 1988 (53 FR 36011).

The remainder of the regulations submitted on August 17, 1989 were published as a proposed approval. EPA proposed approval of the remaining VOC regulations submitted on August 17, 1989, in an NPR on May 29, 1990 (55 FR 21755). That notice proposed approval of all of Massachusetts' August 17, 1989 submittal with the exception of the automobile surface coating regulation.

On November 15, 1990, the Clean Air Act Amendments of 1990 (CAAA) were enacted. In section 182(a)(2)(A) of the amended Act, Congress codified the requirement that states revise their SIPs for ozone nonattainment areas so that they conform with EPA's preamendment guidance.

On June 7, 1991, Massachusetts submitted revisions to its VOC regulations pursuant to the changes requested in the NPRs published in the **Federal Register**. Today's action approves only certain portions of that submittal. Other portions of the June 7, 1991 submittal dealing with gasoline marketing, solvent metal degreasing and surface coating of miscellaneous parts and products are being proposed for approval in a separate action because EPA never proposed them for public comment.[1] In addition, EPA finally approved as a separate action, revisions to Massachusetts' automobile surface coating regulation in the **Federal Register** on October 8, 1992 (57 FR 46313).

On December 17, 1991 the DEP submitted a letter to EPA withdrawing certain portions of the June 7, 1991 submittal due to typographical errors. This letter does not affect the enforceability or approval of today's action because it affects separable rules that are not the subject of today's action.

EPA is taking final action because this action is consistent with the guidance that existed at the time of the proposal and because it strengthens the SIP. Additionally, these amendments, although submitted in response to the SIP call letter, also fulfill part of the RACT fix-up requirement.

Summary of Amendments Made To Secure Final EPA Approval

EPA's NPR published on June 1, 1987, for Massachusetts' generic bubble regulations, required that 15 issues be addressed prior to final rulemaking. In response to these conditions, Massachusetts' August 17, 1989 SIP revision included an amendment in 310 CMR 7.00: Appendix B: (1)(a)7. stating: "The Department will not issue any new approvals for alternative emission limitations to any facility that did not apply in writing for approval prior to May 25, 1988 until these regulations are amended to be consistent with the National Emissions Trading Policy issued on December 4, 1986 and approved into the SIP by EPA." This amendment to Massachusetts' bubble regulation eliminates the State's authority to issue generic bubbles. Therefore, all issues listed in the June 1, 1987 NPR have been resolved.

EPA's NPR published on May 29, 1990 for its revised VOC regulations required that 10 issues be addressed prior to final rulemaking. In the June 7, 1991 submittal, Massachusetts made the following changes to satisfy the requirements as listed in NPR:

1. Several definitions were revised to correct deficiencies and typographical errors specifically outlined in the NPR.

2. The May 29, 1990 NPR listed corrections Massachusetts needed to make to 310 CMR 7.24, "organic material storage and distribution," 310 CMR 7.18(8), "solvent metal degreasing" and 310 CMR 7.18(11), "miscellaneous metal parts and products regulations." Massachusetts made changes to these regulations and submitted them on June 7, 1991. Revisions to regulation 310 CMR 7.24, portions of 310 CMR 7.18(8) and portions of 310 CMR 7.18(11) are being proposed in another notice since the changes submitted on June 7, 1991 were more significant than those required by EPA in the **Federal Register** on May 29, 1990.

3. Massachusetts made a clarification to 310 CMR 7.18(2)(c). Additionally, EPA listed a requirement in the NPR stating that additional language was needed, which specifically said that sources applying for an alternative RACT would be subject to the underlying SIP until EPA approves an alternative RACT for that source. Massachusetts has explained that no exemption exists in the regulations relieving sources from complying with the SIP, therefore, additional language is not warranted. EPA accepts this explanation and concurs with DEP's response.

4. An addition was made to 310 CMR 7.18(2)(e) to include monitoring requirements for emission capture and control equipment.

5. The definition of halogenated organic compound was not officially removed from the submittal. However, the presence of this definition does not affect the enforceability of 310 CMR 7.18 because no regulations referencing this definition have been submitted as part of the SIP. Therefore, EPA is approving this definition.

6. The typographical error in 310 CMR 7.18(12) was corrected.

7. An addition was made to 310 CMR 7.18(3)(a), (4)(a), (5)(a), (6)(a), (10)(a), (14)(a), (15)(a), (16)(a) and (18)(a) to include the language "before application of air pollution control equipment."

8. A change was made to 310 CMR 7.18(17)(a) to clarify the applicability of the regulation. The State also clarified 310 CMR 7.18(17)(f), so that any RACT determination made pursuant to 310 CMR 7.18(17)(a)–(e) must be approved by EPA.

A more detailed description of these revisions and EPA's rationale for approving them was provided in the NPR and will not be restated here. For additional details of each portion of Massachusetts' regulations, see the Technical Support Document prepared on the revision available at the locations listed in the **ADDRESSES** section of this notice.

Response to Public Comments

EPA received 8 letters of public comment; 7 letters were submitted on NPR published on June 1, 1987 on the proposed approval of the generic bubble rule and 1 letter on the NPR published on May 29, 1990. Consequentially, since Massachusetts has recognized that its generic bubble was not consistent with EPA guidance, Massachusetts has amended its generic bubble regulation so that no additional "bubbles" will be issued. Accordingly, EPA has not prepared a response to the comments submitted on June 1, 1987 because the State revised its regulation to disallow emission trading. Furthermore, the letter submitted on the May 29, 1990 NPR by the MA DEP will be addressed when EPA publishes a final rulemaking notice for those actions proposed on September 22, 1992 (57 FR 43651) since that letter addresses revisions to Massachusetts' regulations which were proposed by EPA on September 22, 1992.

Final Action

EPA is approving the SIP revisions submitted by the Commonwealth of Massachusetts on August 27, 1982, June 27, 1984, March 6, 1985, April 12, 1985, August 17, 1989, and portions of the SIP revision request submitted on June 7, 1991. These revisions amend Massachusetts' VOC regulations. For the reasons described here and in the Technical Support Document, EPA is approving the additions and/or

[1] These revisions were proposed in the **Federal Register** on September 22, 1992 (57 FR 43651).

revisions made to the Massachusetts VOC regulations.

Under the Regulatory Flexibility Act, 5 U.S.C. 600 *et seq.*, EPA must prepare a regulatory flexibility analysis assessing the impact of any proposed or final rule on small entities. 5 U.S.C. 603 and 604. Alternatively, EPA may certify that the rule will not have a significant impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and government entities with jurisdiction over populations of less than 50,000.

SIP approvals under section 110 and subchapter I, part D of the CAA do not create any new requirements, but simply approve requirements that the State is already imposing. Therefore, because the Federal SIP-approval does not impose any new requirements, I certify that it does not have a significant impact on any small entities affected. Moreover, due to the nature of the Federal-state relationship under the CAA, preparation of a regulatory flexibility analysis would constitute Federal inquiry into the economic reasonableness of state action. The CAA forbids EPA to base its actions concerning SIPs on such grounds. *Union Electric Co.* v. *U.S. E.P.A.*, 427 U.S. 246, 256–66 (S.Ct. 1976); 42 U.S.C. 7410 (a)(2).

In addition, although portions of these submittals preceded the date of enactment of the CAAA, EPA is approving the submittals as meeting part of the requirements of section 182(a)(2)(A) of the amended Act. Areas designated nonattainment before enactment of the Amendments and which retained that designation and were classified as marginal or above as of enactment are required to meet the RACT fix-up requirement. Under section 182(a)(2)(A), those areas were required by May 15, 1991, to correct RACT as it was required under preamended section 172(b) as that requirement was interpreted in preamendment guidance.[2] The SIP call letters interpreted that guidance and indicated corrections necessary for specific nonattainment areas. The entire state of Massachusetts is classified as a serious, ozone nonattainment area and is, therefore, subject to the RACT fix-up requirement. The portions of Massachusetts' revised regulations that were submitted in response to the SIP call letter, therefore, also fulfill part of the RACT fix-up requirement.

Because EPA proposed approval of this submittal prior to enactment, EPA did not propose approval based on the requirements of new section 182(a)(2)(A). However, EPA believes that the good cause exception to notice-and-comment rulemaking applies and that the Agency, therefore, is not required to repropose approval of the submittal as meeting section 182(a)(2)(A). The Agency's action on a SIP or SIP elements is rulemaking that is subject to the procedural requirements of the Administrative Procedure Act (APA). Section 553(b)(B) of the APA provides that the Agency need not provide notice and an opportunity for comment if the Agency for good cause determines that notice and comment are "impracticable, unnecessary, or contrary to the public interest."

Notice and comment are impracticable and unnecessary in the present circumstance. Section 182(a)(2)(A) does not impose new requirements on the subject nonattainment areas. Rather, section 182(a)(2)(A) codifies the corrections certain nonattainment areas needed to make subject to the EPA SIP call letters issued in 1987 and 1988. Because the Massachusetts SIP submittal meets the SIP call requirements and, therefore, is consistent with the applicable pre-amendment guidance, EPA believes that the submittal also necessarily meets the requirements of section 182(a)(2)(A) of the amended Act. In EPA's earlier proposed approval of the Massachusetts SIP, EPA provided notice and an opportunity for comment on the consistency of the state's rules with EPA's pre-enactment guidance. Since notice and an opportunity for comment have been provided on that set of issues, and section 182(a)(2)(A) does not expand those requirements, it is unnecessary to repeat that process. In addition, it is impracticable for the Agency to take such action because in light of the statutory time constraints on acting on SIPs, such a process would divert valuable agency resources from action on the large number of SIPs addressing new substantive requirements.

This action has been classified as a Table 2 action by the Regional Administrator under the procedures published in the **Federal Register** on January 19, 1989 (54 FR 2214–2225).

On January 6, 1989, the Office of Management and Budget (OMB) waived Table 2 and Table 3 revisions (54 FR 2222) from the requirements of Section 3 of Executive Order 12291 for a period of two years. EPA has submitted a request for a permanent waiver for Table 2 and Table 3 SIP revisions. OMB has agreed to continue the temporary waiver until such time as it rules on EPA's request.

Nothing in this action should be construed as permitting or allowing or establishing a precedent for any future request for revision to any State implementation plan. Each request for revision to the State implementation plan shall be considered separately in light of specific technical, economic, and environmental factors and in relation to relevant statutory and regulatory requirements.

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by March 12, 1993. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

Air pollution control, Hydrocarbons, Incorporation by reference, Intergovernmental relations, Ozone, Reporting and recordkeeping requirements.

Note: Incorporation by reference of the State Implementation Plan for the Commonwealth of Massachusetts was approved by the Director of the Federal Register on July 1, 1992.

Dated: November 12, 1992.

Julie Belaga,

Regional Administrator, Region I.

Part 52 of chapter I, title 40 of the Code of Federal Regulations is amended as follows:

PART 52—[AMENDED]

1. The authority citation for part 52 continues to read as follows:

Subpart W—Massachusetts

Authority: 42 U.S.C. 7401–7671q.

2. Section 52.1120 is amended by adding paragraph (c)(93) to read as follows:

§ 52.1120 Identification of plan.

* * * * *

(c) * * *

[2] Among other things, the preamendment guidance consists of the VOC RACT portions of the Post-87 policy, 52 FR 45044 (Nov. 24, 1987); "Issues Relating to VOC Regulation Cutpoints, Deficiencies and Deviations, Clarification to Appendix D of November 24, 1987 Federal Register Notice" (Bluebook) (notice of availability published in the Federal Register on May 25, 1988); and the existing CTGs.

(93) Revisions to the State Implementation Plan submitted by the Massachusetts Department of Environmental Protection on August 27, 1982, June 27, 1984, March 6, 1985, April 12, 1985, August 17, 1989, June 7, 1991 and December 17, 1991.

(i) Incorporation by reference.

(A) Letters from the Massachusetts Department of Environmental Protection dated August 27, 1982, April 12, 1985, August 17, 1989, and June 7, 1991, submitting revisions to the Massachusetts State Implementation Plan.

(B) Amendment to 310 CMR 7.18(2)(b) submitted on August 27, 1982 and effective on September 16, 1982.

(C) Addition of 310 CMR 7.00: Appendix B submitted on April 12, 1985 and effective on September 30, 1984.

(D) Amendments to portions of 310 CMR 7.00 submitted on August 17, 1989 and effective September 15, 1989.

(E) Amendments to portions of 310 CMR 7.00 submitted on June 7, 1991 and effective on April 12, 1991.

(F) Amendments to portions of 310 CMR 7.00 submitted on June 7, 1991 and effective on June 21, 1991.

(ii) Additional materials.

(A) A letter from the Massachusetts Department of Environmental Quality Engineering dated June 27, 1984 submitting 310 CMR 7.00: Appendix B.

(B) A letter from the Massachusetts Department of Environmental Quality Engineering dated March 6, 1985 submitting additional information on 310 CMR 7.00: Appendix B and referencing 310 CMR 7.18(2)(b).

(C) A letter dated December 17, 1991 from the Massachusetts Department of Environmental Protection withdrawing the emission limit for the Primer-surfacer application in 310 CMR 7.18(7)(b) from the June 7, 1991 submittal.

(D) Nonregulatory portions of state submittal.

3. In § 52.1167 Table 52.1167 is amended by adding new entries to existing state citations for "310 CMR 7.00", "310 CMR 7.18(3)", "310 CMR 7.18(4)", "310 CMR 7.18(5)", "310 CMR 7.18(6)","310 CMR 7.18(8)","310 CMR 7.18(9)", "310 CMR 7.18(10)", "310 CMR 7.18(11)", "310 CMR 7.18(12)", "310 CMR 7.18(13)", "310 CMR 7.18(14)", "310 CMR 7.18(15)", "310 CMR 7.18(16)", "310 CMR 7.18(17)", and "310 CMR 7.18(18)"; and by adding new state citations for "310 CMR 7.02(12)", "310 CMR 7.18(1)", "310 CMR 7.18(2)" and "310 CMR 7.00: Appendix B" to read as follows:

§ 52.1167 EPA-approved Massachusetts regulations.

* * * * *

TABLE 52.1167.—EPA-APPROVED RULES AND REGULATIONS

State citation	Title/subject	Date Submitted by State	Date approved by EPA	Federal Register citation	52.1120 (c)	Comments/unapproved sections
310 CMR 7.00	Definitions	August 17, 1989; June 7, 1991	January 11, 1993	[Insert FR citation from published date].	93	Approving the following amended or additional definitions: Application area, asphalt, automobile, bottom filling, bulk terminal, coating line(s), commissioner, condensate, continuous compliance, crude oil, department, end sealing compound, exterior base coat, extreme environmental conditions, flashoff area, freeboard height, freeboard ratio, halogenated organic compound, interior base coat, interior body spray, knife coating, lease custody transfer, light duty truck, manufacturing plant, miscellaneous metal parts and products, overvarnish, paper surface coating, penetrating prime coat, petroleum liquids, prime coat, publication rotogravure printing, quench area, refrigerated chiller, Reid vapor pressure, roll printing, roll coating, single coat, solids, specialty printing, splash filling, standard conditions, submerged filling, three piece can side seam spray, topcoat, transfer efficiency, two piece can exterior end coating, vinyl surface coating, volatile organic compound, waxy, heavy pour crude oil. The definitions of "coating application system" and "bulk plants and terminals" have been deleted.
310 CMR 7.02(12)	U Organic Material	August 17, 1989	January 11, 1993	[Insert FR citation from published date].	93	310 CMR 7.02(12) has been recodified and relocated in 310 CMR 7.24, "U Organic Material Storage and Distribution." All subsections and references in 310 CMR 7.02(12) have been recodified accordingly.
310 CMR 7.18(1)	U Applicability and Handling Requirements	August 17, 1989	January 11, 1993	[Insert FR citation from published date].	93	Approval of 310 CMR CMR 7.18(1), (a), (c), (d) and (e).

TABLE 52.1167.—EPA-APPROVED RULES AND REGULATIONS—Continued

State citation	Title/subject	Date Submitted by State	Date approved by EPA	Federal Register citation	52.1120 (c)	Comments/unapproved sections
310 CMR 7.18(2)	U Compliance with Emission Limitations	August 27, 1982; August 17, 1989; June 7, 1991	January 11, 1993	[Insert FR citation from published date].	93	Approval of 310 CMR 7.18(2), (2)(a), (2)(b), (2)(c) and (2)(e).
310 CMR 7.18(3)	U Metal Furniture Surface Coating	August 17, 1989; June 7, 1991	January 11, 1993	[Insert FR citation from published date].	93	Replacement of 310 CMR 7.18(3).
310 CMR 7.18(4)	U Metal Can Surface Coating	August 17, 1989; June 7, 1991	January 11, 1993	[Insert FR citation from published date].	93	Replacement of 310 CMR 7.18(4).
310 CMR 7.18(5)	U Large Appliance Surface Coating	August 17, 1989; June 7, 1991	January 11, 1993	[Insert FR citation from published date].	93	Replacement of 310 CMR 7.18(5).
310 CMR 7.18(6)	U Magnet Wire Insulation Surface Coating	August 17, 1989; June 7, 1991	January 11, 1993	[Insert FR citation from published date].	93	Replacement of 310 CMR 7.18(6).
310 CMR 7.18(8)	U Solvent Metal Degreasing	August 17, 1989	January 11, 1993	[Insert FR citation from published date].	93	Approval of 310 CMR 7.18(8), (8)(d), (8)(d)1., (8)(e), (8)(f) and (8)(g).
310 CMR 7.18(9)	U Cutback Asphalt	August 17, 1989	January 11, 1993	[Insert FR citation from published date].	93	Replacement of 310 CMR 7.18(9).
310 CMR 7.10	U Metal Coil Coating	August 17, 1989; June 7, 1991	January 11, 1993	[Insert FR citation from published date].	93	Replacement of 310 CMR 7.18(10).
310 CMR 7.18(11)	U Surface Coating of Miscellaneous Metal Parts and Products	August 17, 1989	January 11, 1993	[Insert FR citation from published date].	93	Approval of 310 CMR 7.18(11), (11)(b), (11)(c), (11)(d) and (11)(e).
310 CMR 7.18(12)	U Graphic Arts	August 17, 1989; June 7, 1991	January 11, 1993	[Insert FR citation from published date].	93	Replacement of 310 CMR 7.18(12).
310 CMR 7.18(13)	U Dry Cleaning Systems-Percholor-ethylene	August 17, 1989	January 11, 1993	[Insert FR citation from published date].	93	Approval of 310 CMR 7.18(13), (13)(c), (13)(d) and (13)(e). 310 CMR 7.18(13)(a) 8. has been deleted.
310 CMR 7.18(14)	U Paper Surface Coating	August 17, 1989; June 7, 1991	January 11, 1993	[Insert FR citation from published date].	93	Replacement of 310 CMR 7.18(14).
310 CMR 7.18(15)	U Fabric Surface Coating	August 17, 1989; June 7, 1991	January 11, 1993	[Insert FR citation from published date].	93	Replacement of 310 CMR 7.18(15).
310 CMR 7.18(16)	U Vinyl Surface Coating	August 17, 1989; June 7, 1991	January 11, 1993	[Insert FR citation from published date].	93	Replacement of 310 CMR 7.18(16).

TABLE 52.1167.—EPA-APPROVED RULES AND REGULATIONS—Continued

State citation	Title/subject	Date Submitted by State	Date approved by EPA	Federal Register citation	52.1120 (c)	Comments/unapproved sections
310 CMR 7.18(17)	U Reasonable Available Control Technology	August 17, 1989; June 7, 1991	January 11, 1993	[Insert FR citation from published date].	93	Approval of 310 CMR 7.18(17), (17)(a), (17)(b), (17)(c), (17)(d), (17)(e) and (17)(f).
310 CMR 7.18(18)	U Polystyrene Resin Manufacturing Technology	August 17, 1989; June 7, 1991	January 11, 1993	[Insert FR citation from published date].	93	Replacement of 310 CMR 7.18(18).
310 CMR 7.00: Appendix B	Alternative Emission Limitations (Bubble) for Volatile Organic Compounds	April 12, 1985; August 17, 1989	January 11, 1993	[Insert FR citation from published date].	93	Addition of 310 CMR 7.00: Appendix B.

[FR Doc. 93–534 Filed 1–8–93; 8:45 am]

BILLING CODE 6560–50–M

40 CFR Part 272

[FRL–4507–1]

Final Authorization of State Hazardous Waste Management Program: Missouri

AGENCY: Environmental Protection Agency (EPA).

ACTION: Immediate final rule.

SUMMARY: The Resource Conservation and Recovery Act of 1976, as amended (RCRA), provides for the U.S. Environmental Protection Agency (EPA) to grant authorization to State agencies to operate their hazardous waste management programs in lieu of the Federal program. The State of Missouri has applied for authorization of revisions to its previously authorized hazardous waste management program under RCRA. EPA has reviewed Missouri's application and has made a decision, subject to public review and comment, that Missouri's hazardous waste management program revision satisfies all of the requirements necessary to qualify for final authorization. Thus, EPA is approving Missouri's hazardous waste management program revisions.

DATES: Final authorization for the Missouri program revisions shall be effective March 12, 1993, unless EPA publishes a prior **Federal Register** action withdrawing this immediate final rule. All comments on Missouri's program revision application must be received by the close of business February 10, 1993. The incorporation by reference of certain Missouri statutes and regulations was approved by the Director of the Federal Register as of March 12, 1993, in accordance with 5 U.S.C. 552(a) and 1 CFR part 51.

ADDRESSES: Copies of Missouri's program revision application are available for inspection and copying during normal business hours at the following addresses: Hazardous Waste Program, Missouri Department of Natural Resources, Jefferson Building, 205 Jefferson Street, Jefferson City, Missouri 65102, Phone: 314–751–3176; U.S. EPA Region VII Library, 726 Minnesota Avenue, Kansas City, Kansas 66101, Phone: 913–551–7241. Written comments should be sent to Gary Bertram, U.S. EPA Region VII, RCRA Branch, 726 Minnesota Avenue, Kansas City, Kansas 66101.

FOR FURTHER INFORMATION CONTACT: Gary Bertram, U.S. EPA Region VII, RCRA Branch, 726 Minnesota Avenue, Kansas City, Kansas 66101; 913–551–7533.

SUPPLEMENTARY INFORMATION:

A. Background

Authorization Process

Section 3006 of RCRA, 42 U.S.C. 6926 *et seq.*, allows EPA to authorize State hazardous waste management programs to operate in the states in lieu of the Federal hazardous waste program. This is done when a state submits to EPA a request for authorization demonstrating that the state program is equivalent to the Federal program.

In addition, as an interim measure, the Hazardous and Solid Waste Amendments of 1984 (Pub. L. 98–616, November 8, 1984, hereinafter referred to as "HSWA") allows States to revise their programs to become substantially equivalent instead of equivalent to RCRA requirements promulgated under HSWA authority. States exercising the latter option receive "interim authorization" for the HSWA requirements under section 3006(g) of RCRA, 42 U.S.C. 6926(g), and later apply for final authorization for the HSWA requirements.

Revisions to State hazardous waste programs are necessary whenever Federal or State statutory or regulatory authority is modified or when certain other changes occur. This is because states with final authorization under section 3006(b) of RCRA have continuing obligations to maintain state programs that are equivalent to, consistent with, and no less stringent than the Federal hazardous waste management program. Most commonly, State program revisions are necessitated by changes to EPA's regulations in 40 CFR parts 260–266 and 124 and 270 that require corresponding changes in the state program in order for the state to maintain its authorization.

EPA Approval of State Programs

EPA codifies its approval of State programs in part 272 of title 40, Code of Federal Regulations (CFR) and incorporates by reference in part 272 the State statutes and regulations that EPA will enforce under section 3008, 3013 and 7003 of RCRA. The purpose of incorporation by reference is to provide clear notice to the public of the scope of the authorized program in each State. Such notice is particularly important in view of the HSWA amendments and the changes in authorized State programs required to reflect these new Federal requirements. By incorporating by reference authorized State programs and by amending the Code of Federal Regulations whenever a new or different

set of requirements is authorized, the status of federally approved requirements in each State will be readily discernible. Thus, EPA is today incorporating by reference the Missouri authorized program in 40 CFR part 272. (See 50 FR 28702, July 15, 1985, for a full discussion of the codification process. For further information, contact EPA Office of Solid Waste, State & Regional Programs Branch, 401 M Street, SW., Washington, DC 20460, Mail Code 5303W.)

The Agency will only incorporate by reference for enforcement purposes those provisions of the Missouri hazardous waste management program for which authorization approval has been granted by EPA. Concerning HSWA, some state requirements may be similar to HSWA requirements that are in effect under Federal statutory authority in that state. However, a state's HSWA-type requirements are not authorized and will not be included in the CFR until the Regional Administrator publishes his final decision to authorize the state for specific HSWA requirements. Until such time, EPA will enforce the HSWA requirements and not the state analogues.

B. Missouri

On November 20, 1985, EPA published a **Federal Register** notice announcing its decision to grant final authorization for the RCRA base program to the State of Missouri (50 FR 47740). EPA's decision to grant authorization for revisions to the Missouri hazardous waste program was published on February 27, 1989 (54 FR 8190).

As noted above, a State with final authorization has a continuing obligation to maintain a hazardous waste program that is equivalent to, consistent with, and no less stringent that the Federal hazardous waste program. To meet its obligation, Missouri submitted a request for additional program approvals. The Missouri request was submitted to EPA on March 8, 1991. The State is seeking approval of its program revision in accordance with 40 CFR 271.21(b)(3).

EPA has reviewed Missouri's application, and determined that Missouri's hazardous waste program revision satisfies all of the requirements necessary to qualify for final authorization. Consequently, EPA is granting final authorization for the additional program modifications to Missouri. Today's decision is being published as an "immediate final" rule in accordance with the provisions of 40 CFR 271.21(b)(3). The public may submit written comments on this immediate final decision until the date noted in the "**DATES**" section of this document. Approval of Missouri's program revision shall become effective 60 days from today unless an adverse written comment pertaining to the State's revision discussed in this notice is received by the end of the comment period. If an adverse comment is received, EPA will publish either (1) a withdrawal of the immediate final decision, or (2) a notice containing a response to comment which either affirms that the immediate final decision takes effect or reverses the decision.

The State has adopted and applied for authorization of the program provisions. For a full discussion of each of the provisions, the reader is referred to the **Federal Register** promulgation of that provision. The provisions are: Radioactive Mixed Waste (July 3, 1986, 51 FR 24504), Standards for Hazardous Waste Storage and Treatment Tank Systems (July 14, 1986), Revised Manual SW–846 (March 16, 1987), Closure/Post-Closure Care for Interim Status Surface Impoundments (March 19, 1987, 52 FR 8704), Definition of Solid Waste (June 5, 1987, 52 FR 21306), Amendments to Part B Information Requirements for Land Disposal Facilities (June 22, 1987, 52 FR 23447), List (Phase 1) of Hazardous Constituents for Ground-Water Monitoring (July 9, 1987, 52 FR 25942), Identification and Listing of Hazardous Waste (July 10, 1987, 52 FR 26012), Liability Requirements for Hazardous Waste Facilities; Corporate Guarantee (November 18, 1987, 52 FR 44314), Hazardous Waste Miscellaneous Units (December 10, 1987, 52 FR 46946), Technical Correction; Identification and Listing of Hazardous Waste (April 22, 1988, 53 FR 13382), Identification and Listing of Hazardous Waste; Treatability Studies Sample Exemption (July 19, 1988, 53 FR 27290), Hazardous Waste Management System; Standards for Hazardous Waste Storage and Treatment Tank Systems (September 2, 1988, 53 FR 34079), Identification and Listing of Hazardous Waste; and Designation, Reportable Quantities, and Notification (September 13, 1988, 53 FR 35412), Statistical Methods for Evaluating Ground-Water Monitoring Data from Hazardous Waste Facilities (October 11, 1988, 53 FR 39720), Identification and Listing of Hazardous Waste; Removal of Iron Dextran from the List of Hazardous Wastes (October 31, 1988, 53 FR 43878), Identification and Listing of Hazardous Waste; Removal of Strontium Sulfide from the List of Hazardous Wastes (October 31, 1988, 53 FR 43881), Hazardous Waste Miscellaneous Units; Standards Applicable to Owners and Operators (January 8, 1989, 54 FR 615), Amendment to Requirements for Hazardous Waste Incinerator Permits (January 30, 1989, 54 FR 4286), and Changes to Interim Status Facilities for Hazardous Waste Management Permits; Modifications of Hazardous Waste Management Permits; Procedures for Post-Closure Permitting (March 7, 1989, 54 FR 9596).

In addition to the seventeen non-HSWA provisions, the State has adopted and requested authorization for the following HSWA provisions: HSWA Codification Rule (With the exception of Delisting and Corrective Action) (July 15, 1985, 50 FR 28702), Burning of Waste Fuel and Used Oil Fuel in Boilers and Industrial Furnaces (November 29, 1985, 50 FR 49164), Listing of Spent Solvents (December 31, 1985, 51 FR 2702), Generators of 100 to 1000 kg Hazardous Waste (March 24, 1986, 51 FR 10146), Codification Rule, Technical Correction (May 28, 1986, 51 FR 19176), Biennial Report; Correction (August 8, 1986, 51 FR 28556), Exports of Hazardous Waste (August 8, 1986, 51 FR 28664), Standards for Generators—Waste Minimization Certifications (October 1, 1986, 51 FR 35190), Listing of EBDC (October 24, 1986, 51 FR 37725), Land Disposal Restrictions (November 7, 1986, 51 FR 40572), HSWA Codification Rule 2 (With the exception of Corrective Action for Injection Wells) (December 1, 1987, 52 FR 45788), and Identification and Listing of Hazardous Waste; Technical Correction (July 19, 1988, 53 FR 27162).

EPA has reviewed the State program in light of current and proposed activities and has determined that authorizing these new provisions will not have a profound effect on the ability of the State to carry out the program.

The State requested authorization for Direct Action Against Insurers (November 8, 1984, HSWA section 3004(t)), however, EPA has determined this to be a non-delegable authority. Reference to this provision remains in the State Authorization Request, however, authorization for the provision is not granted.

The State is not currently requesting Corrective Action authority. Any reference to Corrective Action in the State Authorization Request is not authorized by this notice.

The State will assume lead responsibility for issuing permits for those program areas authorized today. For those HSWA provisions for which the State is not authorized, EPA will retain lead responsibility. For those

permits which will now change to State lead from EPA, EPA will transfer copies of any pending applications, completed permits or pertinent file information to the State within thirty days. EPA will be responsible for enforcing the terms and conditions of federally issued permits while they remain in force. EPA will also be responsible for enforcing the terms and conditions of RCRA permits regarding HSWA provisions that the State does not have the authority to address. The State has agreed to review all State issued permits and to modify or reissue them as necessary to require compliance with the currently approved State law and regulations. When the State reissues federally issued permits as State permits, EPA will rely on the State to enforce them, with the exception of those HSWA provisions not yet authorized.

C. Decision

I conclude that Missouri's application for program revisions meets all of the statutory and regulatory requirements established by RCRA. Accordingly, Missouri is granted final authorization to operate its hazardous waste management program, as revised. Missouri now has responsibility for the permitting of treatment, storage and disposal facilities within its borders and carrying out other aspects of the RCRA program, subject to the limitation of its revised program application and previously approved authorities. Missouri also has primary enforcement responsibilities, although EPA retains the right to conduct inspections under sections 3007, 3013, and 7003 of RCRA.

D. Missouri Authorized Hazardous Waste Program

As noted above, EPA is incorporating by reference for enforcement purposes those provisions of the Missouri hazardous waste management program for which authorization approval has been granted by EPA.

The Missouri authorized hazardous waste program is incorporated by reference in subpart AA to part 272 title 40 of the CFR. The State statutes and regulations are incorporated by reference at § 272.1301(a) and the Memorandum of Agreement, the Attorney General's Statement and the Program Description are referenced at § 272.1301(b), (c) and (d), respectively.

The Agency retains the authority under sections 3008, 3013 and 7003 of RCRA to undertake enforcement actions in authorized states. With respect to such an enforcement action, the Agency will rely on Federal sanctions, Federal inspection authorities and the Federal Administrative Procedure Act rather than the State authorized analogues to these requirements. Therefore, the Agency does not intend to codify for purposes of enforcement such particular, authorized Missouri enforcement authorities. Section 272.1301(a) lists those Missouri authorities that are part of the authorized program but are not codified.

The public also needs to be aware that some provisions of the State's hazardous waste management program are not part of the Federally authorized State program. These non-authorized provisions are not part of the RCRA subtitle C program because they are "broader in scope" than RCRA subtitle C. As a result, State provisions which are "broader in scope" than the Federal program are not incorporated by reference for purposes of enforcement in part 272. Section 272.1301(a) lists for reference and clarity the statutory and regulatory provisions which are "broader in scope" than the Federal program and which are therefore not part of the authorized program being incorporated by reference. "Broader in scope" provisions will not be enforced by EPA; the State, however, will continue to enforce such provisions.

E. HSWA Provisions

As noted above, the Agency is not amending part 272 to include many HSWA requirements and prohibitions that are immediately effective in all States. Section 3006(g) of RCRA provides that any requirement or prohibition of HSWA (including implementing regulations) takes effect in authorized states at the same time that it takes effect in non-authorized states. Thus, EPA has immediate authority to implement a HSWA requirement or prohibition once it is effective. A HSWA requirement or prohibition supersedes any less stringent or inconsistent State provision which may have been previously authorized by EPA. (See 50 FR 28702, July 15, 1985.) Because of the vast number of HSWA statutory and regulatory requirements taking effect over the next few years, EPA expects that many previously authorized and incorporated by reference State provisions will be affected. The States are required to revise their program to adopt the HSWA requirements and prohibitions by the deadlines set forth in 40 CFR 271.21, and then to seek authorization for those revisions pursuant to part 271. EPA expects that the States will be modifying their program substantially and repeatedly. Instead of amending part 272 every time a new HSWA provision takes affect under the authority of RCRA section 3006(g), EPA will wait until the state receives authorization for its analog to the new HSWA provision before amending the state's part 272 incorporation by reference. In the interim, persons wanting to know whether a HSWA requirement or prohibition is in effect should refer to 40 CFR 271.1(j), as amended, which lists each such provision.

The incorporation by reference of State authorized programs in the CFR should substantially enhance the public's ability to discern the current status of the authorized State program and clarify the extent of Federal enforcement authority. This will be particularly true as more State program revisions to adopt HSWA provisions are authorized.

Certification Under the Regulatory Flexibility Act

Pursuant to the provisions of 4 U.S.C. 605(b), I hereby certify that this authorization will not have a significant economic impact on a substantial number of small entities. This authorization effectively suspends the applicability of certain Federal regulations in favor of Missouri's program, thereby eliminating duplicative requirements for handlers of hazardous waste in the State. It does not impose any new burdens on small entities. This rule, therefore, does not require a regulatory flexibility analysis.

Compliance With Executive Order 12291

The Office of Management and Budget has exempted this rule from the requirements of Section 3 of Executive Order 12291.

List of Subjects in 40 CFR Part 272

Administrative practice and procedure, Confidential business information, Hazardous waste, Hazardous waste transportation, Incorporation by reference, Intergovernmental relations, Penalties, Reporting and recordkeeping requirements.

Dated: August 31, 1992.

Morris Kay,

Regional Administrator.

For the reasons set forth in the preamble, 40 CFR part 272 is amended as follows:

PART 272—APPROVED STATE HAZARDOUS WASTE MANAGEMENT PROGRAMS

1. The authority citation for part 272 continues to read as follows:

Authority: Secs. 2002(a), 3006, and 7004(b) of the Solid Waste Disposal Act, as amended

by the Resource Conservation and Recovery Act, as amended, 42 U.S.C. 6912(a), 6926, and 6974(b).

2. Section 272.1 is revised to read as follows:

§ 272.1 Purpose and scope.

This part sets forth the applicable State hazardous waste management programs under section 3006(b) of the Resource Conservation and Recovery Act (RCRA), 42 U.S.C. 6926, and 40 CFR 260.10. "State" is defined in 42 U.S.C. 1004(31) as "any of the several States, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands."

3. Section 272.2 is added to read as follows:

§ 272.2 Incorporation by reference.

Material listed as incorporated by reference in part 272 was approved for incorporation by reference by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Material is incorporated as it exists on the date of the approval, and notice of any change in the material will be published in the **Federal Register**. Copies may be obtained or inspected at EPA Waste Management Rules Docket, 401 M Street, SW., Washington, DC 20460 and at the appropriate EPA Regional Office. Copies may be inspected at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC. For an informational listing of the State and local requirements incorporated in part 272, see appendix A to this part.

4. Section 272.1301 is amended by revising the introductory text and paragraphs (a), (b) and (c)(2) to read as follows:

§ 272.1301 State-administered program; Final authorization.

Pursuant to section 3006(b) of RCRA, 42 U.S.C. 6926(b), Missouri has final authorization for the following elements as submitted to EPA in Missouri's program application for final authorization which was approved on November 20, 1985. Subsequent program revision applications were approved on February 27, 1989, and March 12, 1992. Copies may be obtained from the Hazardous Waste Program, Missouri Department of Natural Resources, P.O. Box 176, Jefferson City, Missouri 65102.

(a) *State statutes and regulations.* (1) The Missouri statutes and regulations cited in this paragraph are incorporated by reference as part of the hazardous waste management program under subtitle C of RCRA, 42 U.S.C. 6921 *et seq.*

(i) Missouri Statutory Requirements Applicable to the Hazardous Waste Management Program, 1990.

(ii) Missouri Regulatory Requirements Applicable to the Hazardous Waste Management Program, December 31, 1990.

(2) The following statutes and regulations, although not incorporated by reference for enforcement purposes, are part of the authorized State program. The statutory provisions include: 260.360(4), 260.360(20)–260.377, 260.393–260.394, 260.400, 260.410–260.420, 260.425–260.430. The regulatory provisions include 3.260(1)(A)24–3.260(1)(A)25, 3.260(1)(B)–3.260(1)(D), 4.261(2)(D)3, 5.262(2)(B)2, 5.262(2)(C)2, 5.262(2)(D)1, 6.263(2)(A)10.D–6.263(2)(A)10.I, 6.263(2)(D)3, 7.264(2)(B)1, 7.265(2)(B), 7.266(2)(E)–7.266(2)(E)3, 7.268(2)(A)1, 7.268(2)(A)3, 7.268(2)(E), 7.270(2)(B)12–7.270(2)(B)13, 7.270(2)(B)18, 7.270(2)(C)1.D, 7.270(2)(C)3, 7.270(2)(D)4.

(3) The following statutory and regulatory provisions are broader in scope than the Federal program, and are not part of the authorized State program. The statutory provisions include: 260.360(13), 260.379, 260.380–1.(10), 260.385(1), 260.390(8), 260.391, 260.395–1–260.295–5, 260.395–7.(5)–260.395–7.(6), 260.396, 260.405, 260.423–260.424, 260.431–260.434. The regulatory provisions include: 3.260(1)(A)21, 4.261(2)(A)6–4.261(2)(D)2, 5.262(2)(I), 6.263(2)(A)3–6.263(2)(A)4, 7.264(2)(P), 7.266(2)(C)–7.266(2)(D), 7.266(2)(E)4–7.266(2)(G), 7.270(2)(B)7–7.270(2)(B)8, 7.270(2)(B)10, 7.270(2)(C)1.A, 7.270(2)(H).

(b) *Memorandum of Agreement.* The Memorandum of Agreement between EPA Region VII and the Missouri Department of Natural Resources, signed by the EPA Regional Administrator on August 30, 1988, and the subsequent Agreement signed on August 31, 1992 are referenced as part of the authorized hazardous waste management program under subtitle C of RCRA, 42 U.S.C. 6921 *et seq.*

(c) * * *

(2) "Attorney General's Statement for Final Authorization of Changes to the Federal RCRA Program," signed by the delegated Assistant Attorney General of Missouri on December 1, 1987, and the subsequent Statement signed on February 28, 1992, are referenced as part of the authorized hazardous waste management program under subtitle C of RCRA; 42 U.S.C. 6921 *et seq.*

* * * * *

5. Appendix A to part 272 is added to read as follows:

Appendix A to Part 272

The following is an informational listing of the State and local requirements incorporated in part 272 of the Code of Federal Regulations:

The statutory provisions include: 260.350–260.360(3), 260.360(5)–260.360(12), 260.360(14)–260.360(19), 260.380–1.–260.380–1.(9), 260.380–2., 260.385(2)–260.390(7), 260.390(9), 260.395–6.–260.395–7.(4), 260.395–7.(7)–260.395–18.

The regulatory provisions include: 3.260–3.260(1)(A)20, 3.260(1)(A)22–3.260(1)(A)23, 3.260(2), 4.261–4.261(2)(A)5, 5.262–5.262(2)(B)1., 5.262(2)(B)3.–5.262(2)(C)1., 5.262(2)(C)2.A.–5.262(2)(D), 5.262(2)(D)2.–5.262(2)(H), 6.263–6.263(2)(A)2., 6.263(2)(A)5.–6.263(2)(A)10.C, 6.263(2)(B)–6.263(2)(D)2., 7.264–7.264(2)(A)2., 7.264(2)(B)2.–7.264(2)(O), 7.264(2)(X), 7.265–7.265(2)(A), 7.265(2)(E)–7.265(2)(K), 7.266–7.266(2), 7.268–7.268(2), 7.268(2)(A)., 7.268(2)(A)4.–7.268(2)(C), 7.270–7.270(2)(B)6., 7.270(2)(B)9., 7.270(2)(B)11., 7.270(2)(B)14.–7.270(2)(B)17., 7.270(2)(C)–7.270(2)(C)1., 7.270(2)(C)1.B.–7.270(2)(C)1.C., 7.270(2)(C)2.–7.270(2)(C)2.C., 7.270(2)(C)2.E., 7.270(2)(D)–7.270(2)(D)3., 7.270(2)(E)–7.270(2)(G).

[FR Doc. 93–196 Filed 1–8–93; 8:45 am]

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DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

49 CFR Part 571

[Docket No. 87–6; Notice 5]

RIN 2127–AD64

Federal Motor Vehicle Safety Standards Lamps, Reflective Devices, and Associated Equipment

AGENCY: National Highway Traffic Safety Administration (NHTSA), DOT.

ACTION: Final rule.

SUMMARY: This final rule facilitates the introduction of daytime running lamps (DRLs) as an item of optional motor vehicle lighting equipment. The purpose of the rule is to ensure that manufacturers may offer DRLs in all 50 States, and that specifications are adopted so that DRLs do not reduce the current level of highway safety. Any pair of lamps that Standard No. 108 requires on the front of a vehicle (other than parking lamps), or other lamps (except for fog lamps) with lenses marked "DRL", may serve as DRLs by automatically operating during daylight, provided that the minimum candela output of each lamp exceeds 500 at test point H–V, and that the maximum

candela output does not exceed 3,000 at any location (or 7,000 at test point H–V if the lamp is mounted no higher than 864 mm (34 in.), and that steps are taken to prevent their light from masking turn and hazard warning signals.

DATES: Effective date of the final rule is February 10, 1993.

ADDRESSES: Petitions for reconsideration should refer to Docket 87–6; Notice 5, be addressed to the Administrator, and be submitted to: Docket Section, room 5109, Nassif Building, 400 Seventh Street, SW., Washington, DC 20590.

FOR FURTHER INFORMATION CONTACT: Jere Medlin, Office of Rulemaking, NHTSA, Washington, DC [202–366–5276].

SUPPLEMENTARY INFORMATION: On March 24, 1987, NHTSA opened Docket 87–6, to receive comments on a notice of proposed rulemaking (NPRM) under which Motor Vehicle Safety Standard No. 108 would be amended to permit daytime running lights (DRLs) as optional front lighting equipment on passenger cars, multipurpose passenger vehicles, trucks, and buses (Notice 1). In 1988, NHTSA announced that it was terminating rulemaking on the subject without an amendment (Notice 2), and later that year it denied a petition for reconsideration of the termination (published without docket or notice number, but referred to as Notice 3). The agency reopened rulemaking in 1991, and published a proposal (Notice 4) upon which this final rule is based. The reader is referred to these notices for background information on this topic (52 FR 8316, 53 FR 23673, 53 FR 40921, and 56 FR 38104).

Rulemaking Petition for DRLs

Notice 4 implemented the grant of a petition for rulemaking submitted by General Motors Corporation (GM). The petitioner asked the agency to facilitate the introduction of motor vehicles to be equipped with DRLs. In GM's view, such an amendment "would allow manufacturers to install DRLs on new vehicles without being in violation of the multitude of state laws which currently have the unintended effect of prohibiting them." However, GM did not believe that there is justification for mandating DRLs as standard equipment because there is not yet evidence of a "national safety need" in the United States. Because DRLs are more effective in Northern latitudes where ambient daytime light levels differ from those of the South, they appear to have a greater likelihood of assisting in crash prevention in Alaska or Maine, instead of Florida or Hawaii. Further, as GM had noted in 1987, fuel economy may be reduced by as much as a quarter mile per gallon when some DRLs are used. The petitioner argued that the ability to test DRLs on vehicles in the U.S. could enable it to assess the potential safety benefits of DRLs in this country, and at the same time, their limited use would minimize the penalty of overall fleet fuel economy.

In response to Notice 4, comments were submitted from the following 27 respondents, listed in the order received: John W. Kourik, P.E., Virginia State Police (Virginia), American Motorcycle Association, Department of California Highway Patrol (California), Navistar International, Carter Hart, Ontario Ministry of Transport, Mack Trucks, Inc. (Mack), Hino Motors Inc. (Hino), Saab Cars USA, Inc., Truck-Lite Co. Inc., Volkswagen of America, Inc. (VW), University of Michigan Transport Research Institute, Hella KG, American Honda Motor Co., General Electric Lighting (GE), C.R. Blydenburgh, National Automobile Dealers Association, Volvo Cars of North America, Motor Vehicle Manufacturers Association (MVMA), General Motors Corporation (GM), Advocates for Highway and Auto Safety (Advocates), Chrysler Corporation, American Automobile Association, Ford Motor Company, Insurance Institute for Highway Safety (IIHS), and Ohio Department of Public Safety (Ohio).

Existing State Laws That Could Prohibit DRLs

NHTSA was not aware of any State laws that prohibit DRLs per se. However, GM brought to the agency's attention State laws requiring pre-approval of supplemental lighting devices, and the fact that there is currently no SAE standard for DRLs on which such approval could be based. Further, GM found a variety of State laws that might affect DRLs. 35 States have regulations prohibiting supplemental lighting from projecting light that strikes the roadway at a specified distance in front of the vehicle. In addition, there appeared to be State laws which prohibit the use of lights in tunnels, the use of the parking lamps without headlamps when the car is being driven, and the illumination of fog lamps without the headlamps. GM, which offers DRLs in Canada as mandated by that country's lighting standard, stated that it was impossible to determine whether a particular DRL design that it uses there would be prohibited under this array of State laws. It concluded that DRLs are potentially affected by the laws of 40 to 45 States.

GM also argued that the trend in State lighting laws is towards increasing the daytime conspicuity of vehicles, and that allowing DRLs would be consistent with this trend. Several jurisdictions (Cape Cod and the State of Washington are referenced) now require 24-hour a day headlamp use on some roads. Legislation to mandate DRLs has been introduced in Connecticut. California now specifically regulates DRLs, but only those that are optionally installed. Thus, GM argued that adding a DRL provision to Standard No. 108, thereby preempting under 15 U.S.C. 1392(d) State laws prohibiting DRLs, would not contravene the spirit of Executive Order 12612 (Federalism).

NHTSA reviewed these arguments. It believes that manufacturers who wish to offer this option should not be precluded from doing so, provided that their DRLs do not derogate from existing levels of highway safety. For example, the agency believes that it is necessary to amend Standard No. 108 in a way that ensures the States do not allow DRLs having an intensity that may cause excessive glare. Therefore, NHTSA issued an NPRM to achieve these objectives.

In drafting the proposal, the agency took careful note of the Executive Order on Federalism which seeks to limit preemption of State laws, but recognizes the right of a Federal agency to preempt a State where Congress has provided express preemption authority, such as exists in 15 U.S.C. 1392(d). NHTSA sought to minimize, to the extent consistent with safety, the preemptive effect of the NPRM in accordance with the regulatory philosophy behind the Executive Order. It believed that the Executive Order on Federalism is primarily concerned with Federal preemption of State laws that differ in a fundamental manner from Federal requirements. In this instance, there is no State law that prohibits DRLs per se. Thus, a Federal standard whose effect is to allow DRLs would not be directly preemptive of existing State laws, since there is no existing State law that expressly prohibits DRLs.

The Executive Order requires NHTSA to examine the indirect, as well as the direct, preemptive effect of its regulations as well. NHTSA considered the issue of whether an amendment allowing DRLs would, as a matter of law, preempt State laws that do not deal with DRLs, but whose provisions might be construed to prohibit them. The agency concluded that its preemption authority addresses this possibility as well. Under section 1392(d), NHTSA's safety standards preempt those State standards covering "the same aspect of

performance". This is a broad phrase, and is to be interpreted broadly in the fulfillment of the agency's mission. Therefore, to the extent that any State standard might affect the operation and performance of front lamps used as DRLs, NHTSA considers that, to the same extent, such a State standard may be viewed as covering the same aspect of performance as NHTSA's DRL specifications. For example, if Standard No. 108 allows lamps to be wired to operate automatically as DRLs, and to be specifically marked "DRL", the performance of that lamp is no longer subject to State restrictions on daytime use. As a further example, if the DRL that would be allowed under this rulemaking were provided by a pair of new lamps, and not by the existing lamps required by Standard No. 108, NHTSA believes that such a lamp system would be covered by Standard No. 108, instead of being considered supplementary lighting devices subject to state approval programs for supplemental equipment. Given the apparent trend in the States toward promoting greater daytime conspicuity for motor vehicles, NHTSA argued that preempting the indirect effects of State regulations would be acceptable under the regulatory philosophy of Executive Order 12612.

However, NHTSA did not wish to proceed to a final rule without offering States an opportunity to comment on the safety rationale of statutes and regulations that might be preempted by NHTSA action. For example, comments were invited on the effects that might be attendant to overriding a state prohibition against headlight use in tunnels, or against use of parking lamps alone.

California appeared to be the only state with a DRL law that would be preempted by a Federal specification. Its more stringent regulation establishes a minimum intensity of 500 candela for DRLs, the effect of which is to prohibit the use of parking lamps for this purpose, since the maximum intensity permitted for these lamps is only 250 candela. In its comments, California urged that the States be allowed to continue to regulate DRLs. While NHTSA has decided to adopt its proposal to regulate DRLs, it has, in response to California's comment, adopted a 500 candela minimum in the final rule. The agency notes that this minimum requirement also exists in the Canadian standard for certain non-headlamp DRLs. A proposal to adopt such a minimum appeared in an earlier notice in this series of notices on DRL.

The responses to Notice 4 did not note any State laws that would be inadvertently preempted by Federal DRL requirements. Those states that commented did so in relation to the effects on enforcement of other State laws. The NPRM proposed a maximum DRL mounting height of 83 inches (the maximum permissible for turn signal lamps), far higher than the maximum of 42-inches allowed for auxiliary lamps in Minnesota, Mississippi, and Iowa. The final rule limits DRLs that are not combined with other required lighting equipment to a mounting height of 1.067 m (42 inches) in recognition of the laws of these States.

Virginia requires taillamps to be activated when fog lamps are used, but commented that taillamp use would not be desirable when DRLs are used. California requires that fog lamps be connected to the headlamp circuit. Thus, in California, if DRLs were combined with fog lamps, the headlamps would have to be on. NHTSA has reviewed these comments and understands how the States perceive that a DRL specification might appear to preempt their laws. NHTSA does not believe that having a DRL within a fog lamp actually preempts a State law; however, it might make it more difficult for a State to enforce its law. Thus, to avoid any question of express or implied preemption, NHTSA has decided to exclude fog lamps from use as DRLs.

Front Lamps Likely To Be Used as DRLs

With a few exceptions, the final rule permits the use of any front lamps, whether required by Standard No. 108 or not, as DRLs. For the reasons discussed above, neither parking lamps nor fog lamps may be used as DRLs. On some vehicles, the DRL may be optically combined with a headlamp, i.e., provided by the lower headlamp beam at full or reduced intensity, and, on others, by the upper headlamp beam at a reduced intensity. DRLs may be optically combined with the turn signal lamps and used at the same operational intensity. DRLs may also be provided by a pair of front lamps specifically designed for this purpose.

The NPRM did not address the use of the lower beam headlamps as DRLs, either at full or lower intensity. Both are permitted in Canada. No commenter addressed this issue. There appears to be no reason to prohibit use of the lower beam at full intensity as a DRL. If the lower beam were used for DRLs, one might expect the side and taillamps to be activated when the DRLs are activated just as the side and taillamps are when the lower beam is used for road illumination purposes; in fact, this is a requirement in Canada. However, Canada does not require illumination of the side and taillamps when the lower beam is used at a reduced intensity. NHTSA is concerned about this. The intensity of the lower beam is reduced to about 70 percent of full intensity, creating the possibility that vehicles so equipped will be driven in the DRL mode at night without side and rear marking, instead of with their headlamps at full lower beam intensity. Although the final rule allows use of a lower intensity of a lower beam without activation of side and rear lamps, NHTSA will consider proposing simultaneous activation, or a "DRL on" indicator should accident or complaint records show an emerging problem.

See the further discussion of lower beam photometrics in the section of this notice on "Lamp Intensity."

Appropriate Performance Requirements for DRLs-GM's Recommendation

GM called the agency's attention to three possible models on which to base the agency's DRL requirements. These were the requirements adopted by Canada, those proposed by NHTSA in Notice 1, and those currently under consideration by the SAE in its draft Recommended Practice J2087 Daytime Running Lamps for Use on Motor Vehicles. GM strongly supported adoption of the Canadian requirements because it would facilitate transfer of existing DRL designs in Canada to U.S. production with minimum cost and delay, and that the U.S. standard should harmonize with the Canadian one. With respect to the agency's proposal in Notice 1, GM asked NHTSA to consider the remarks it made in response to it, as the company continued to have reservations about the proposal. Finally it had no fundamental objections to the SAE document and believed that the design criteria contained therein are sufficiently flexible to accommodate many of the DRL designs presently used in Canada.

NHTSA's 1991 NPRM

Notice 4 and this final rule are based upon several considerations. First, some regulation of DRLs is necessary to ensure that they perform in a manner that does not detract from existing levels of highway safety. The two chief goals in this regard are ensuring that the lamps do not create excessive glare, and that their use does not mark the ability of the front turn signal to send its message. To address these issues, the NPRM set forth some very simple proposals. It would establish a maximum candela limitation, a

minimum spacing requirement affecting the distance of a DRL from the turn signal lamp, and a requirement that the lens of any lamp used as a DRL, other than a headlamp, be marked "DRL". It would also specify a range of permissible colors, and that DRLs be provided in pairs, instead of a single lamp. The specific characteristics of a DRL system are discussed below.

A. Number of DRLs

For some years, the single headlamp on a great majority of motorcycles has been wired to light when the ignition is on. This design has provided a DRL for motorcycles. In order to avoid possible misidentification of four-wheeled vehicles as motorcycles, which are much narrower than other vehicles, NHTSA tentatively concluded that the DRL "signature" for vehicles other than motorcycles should be comprised of two symmetrically located lamps. No commenter opposed the proposal, or suggested any benefits accruing from the provisions of a single DRL on 4-wheeled vehicles. Therefore, the DRL system that will be required for vehicles other than motorcycles will consist of a pair of front lamps.

B. Lamp Color

Required lighting equipment under Standard No. 108 may be red, white, or yellow (paragraph S5.1.5) as defined by SAE Standard J578c, February 1977. Standard No. 108 reserves the use of red to rear lighting devices. In addition, red (and blue) are used by States to denote emergency, police, or towing vehicles. NHTSA tentatively concluded in the NPRM that the color of a DRL should be one that the motoring public associates with the front of a vehicle, that is to say, either white or yellow. Thus, if a headlamp or turn signal lamp were used as a DRL, the light from the DRL would be the same color as the light from that lamp. If a front lamp other than one of these were used as a DRL, manufacturers would be required to choose among the following color range: white, white to yellow, white to selective yellow, yellow, or selective yellow, as defined in SAE Standard J587 MAY88.

Comments varied on the proposal. Virginia, Michigan, and GM opted for white, a color associated with the front of motor vehicles, while Ohio and Advocates wanted a color with yellow in it because, in adverse lighting conditions, the amber spectrum is more visible than white. Others, such as Chrysler, supported the NPRM as written. NHTSA has reviewed these comments, and finds no safety disbenefit to allowing any of the colors proposed. Therefore, the color requirements are adopted as proposed.

C. Lamp Intensity

The effectiveness of interior and exterior rear view mirrors is essential for safe vehicle operation in traffic at all times of day. It is important, therefore, to ensure that DRL operation does not interfere with mirror use. NHTSA has completed three research programs to determine acceptable limits of DRL intensity. The most recent, "Evaluation of Glare from Daytime Running Lights", October 1989 (DOT–HS–807–502), is the basis for NHTSA's proposal. (See also "Evaluation of the Conspicuity of Daytime Running Lights", April 1990 (DOT–HS–807–613), and "A Study of Daytime Running Light Design Factors", August 1987 (DOT–HS–807–193). Copies of the three Reports are available in NHTSA's Technical Reference Library.)

The 1989 Report addresses driver perceived glare increases from a succession of increasingly intense DRLs. Separate experiments covered by this Report provided subjective data which indicated that approximately 2,800 candela can be tolerated before the "Just Acceptable" rating on the De Boer glare scale is exceeded. Under Standard No. 108, the maximum allowable intensity of glare test points of a complying lower beam is 2,700 candela. The effect of the proposal was that a lower beam that provides the maximum allowable candela could not function as a DRL. For these reasons, NHTSA tentatively concluded that 2,600 candela appeared to be an appropriate value regardless of how a DRL is provided, and that a maximum for the DRL compatible with the maximum for glare of the U.S. lower beam should be acceptable to U.S. drivers.

Commenters disagreed with NHTSA. Vehicle manufacturers and IIHS urged the agency to allow 7,000 candela at test point H–V as a maximum intensity for two reasons. The simplest DRL is an upper beam headlamp operating at half the voltage with a maximum output at H–V of about 7,000 candela. Canada allows a maximum of 7,000 candela at H–V for a DRL provided by a reduced intensity upper beam headlamp, even though the intensity could be higher elsewhere. Further, Ford, Chrysler, GM, and MVMA questioned the agency's research that led to the proposed limit of 2,600 candela. This limit, nevertheless, was supported by Virginia, Ohio, Advocates, John Kourik, VW, and by GE with respect to certain test points above the horizontal.

There are two kinds of glare: That which discomforts and that which disables. The agency proposed 2,600 candela to limit discomfort from glare from rear view mirrors caused by vehicles with DRLs following closely behind. Canada, however, has adopted a maximum value of 7,000 candela at test point H–V, which was supported by some commenters, and NHTSA reexamined its position on this issue.

In its reexamination, NHTSA proceeded with the assumption that the most likely DRL would be an upper beam headlamp operated at low voltage (the type of DRL found on approximately 53 percent of Canadian DRL-equipped vehicles). The second assumption was that it was unlikely that the greater percentage of DRLs would be mounted at an exterior height near the height of an interior rear view mirror so that they would project light directly upon it. Higher mounted DRLs appeared most likely to be on a comparatively small part of the vehicle population, larger trucks and multipurpose passenger vehicles. The intensity of the upwardly directed light rays of upper beams diminishes rapidly as the angle above the horizontal increases. NHTSA's calculations show, for example, that only 220 to 350 candela would be directed into the rear view mirror of a Honda Civic CRX (mirror height 44 inches) by DRLs of 6,600 candela on a Ford Taurus or Buick Regal (headlamp height 25.5 inches) about one car length (20 feet) behind. The steady intensity of light in the mirrors of cars being followed by cars with DRLs of 7,000 candela at test point H–V would be only about one eighth of the level considered to be discomforting. The driver of a small car would not be exposed to an intensity greater than 2,600 candela unless the mounting height of the DRL of the vehicle behind exceeded 34 inches. This conclusion takes into consideration the imperfectly centered pattern of an actual headlamp (the maximum intensity is not always located at H–V) as well as one half degree upward misaim of the lamp. NHTSA has therefore concluded that DRLs with a maximum intensity of 7,000 at H–V candela may be allowed as long as they are mounted at a height that does not exceed 34 inches, and has so stated in the final rule.

This leaves the question of the appropriate maximum value for DRLs mounted higher than 34 inches. Manufacturers commenting to Notice 4 stated that the proposed 2,600 candela was not practicable. For the reasons set forth below, NHTSA has chosen 3,000 candela as the maximum beam intensity.

The lower limit in Canada for the upper beam operated at low voltage is

2,000 candela. Standard No. 108 establishes a limit of 75,000 candela at test point H–V for the upper beam. Sealed beam headlamps designed to conform to SAE J579c achieve 50,000 to 75,000 candela in NHTSA tests. If a manufacturer were to design an upper beam headlamp to operate as a DRL, it would need to provide an intensity reducing device that achieves only 4 percent of the nominal intensity to give a range. Chrysler of Canada uses similar devices to achieve reduced intensities below 4,500 candela. NHTSA believes that it is possible to adjust these devices to provide lower intensities, and that this is likely to be the most practicable means in the range necessary to minimize discomfort glare, 2,000 to 3,000 candela. If a manufacturer is unable to achieve this limitation by use of upper beam headlamps, it may still use lower beam headlamps, either at full or reduced intensity.

Finally, under the NPRM, DRL photometry would be tested in accordance with SAE J575 DEC88, when a test voltage of 12.8V +/– 20 mV is applied to the input terminals of the DRL lamp switch module or voltage-reducing equipment, whichever is closer to the electrical source on the vehicle. The test distance from the DRL to the photometer would be not less than 18.3 meters (60 feet) if the DRL is optically combined with a headlamp, or 3 meters (10 feet) if the DRL is a lamp, or is optically combined with a lamp other than a headlamp.

GM commented that it did not understand the reference to SAEJ575 and recommended deletion. The final rule clarifies that NHTSA intended to refer only to the photometric test procedures. The NPRM erroneously referenced S5.5.11(b) as the criteria to be met in the photometric test, and the rule corrects that provision so that it refers to S5.5.11(a).

D. Turn Signal Masking Effect

Notice 1 would have prohibited operation of a DRL when a turn signal or hazard warning signal is activated if the distance from the lighted edge of the DRL to the optical axis of the turn signal lamp were less than 4 inches. Notice 4 reproposed this prohibition. However, the spacing requirement would not apply if the turn signal lamp complies with the increased intensity specifications of S5.3.1.7 of Standard No. 108, or if the DRL is deactivated when the turn or hazard warning signal is on.

GM stated that the spacing requirement is an unnecessary impediment to DRLs combined with upper beam headlamps, and is inconsistent with the Canadian standard. It provided data from an SAE Committee test in which observers were asked if they could detect a turn signal of 250 candela located 3/8ths of an inch from a DRL of 5,000 candela at a distance of 500 feet. Although GM stated that performance was acceptable, the data that it submitted indicate that only 46.9 percent of the observers could see the turn signal. This is far below the 80 percent that the SAE considers the minimum acceptable for incorporation into its standards.

Contrary to GM's assertion, NHTSA's proposal and the Canadian requirements for DRL-turn signal spacing are identical. Additionally, the data provided by GM contradicts its assertion that a spacing requirement is unnecessary. After submitting its data, GM supplemented its submission, saying that the data implied that the turn signals would have been more visible at distances less than the test distance of 500 feet, and that turn signal visibility is not necessary beyond 200 feet. Since the stopping distance of trucks from 60 mph is 200 to 300 feet, NHTSA does not consider that 200 feet is an adequate distance. At least one state, Indiana, requires turn signal use for at least 200 feet before turning or changing lanes, unless the speed limit is 50 mph, in which case the distance is 300 feet.

NHTSA conducted its own demonstration for 9 members of the agency staff. The test distance was 300 feet. The test DRL intensities were 2,600, 5,000, and 7,000 candela. The turn signal intensities were 250 and 500 candela. The turn signal/DRL spacings were 2 and 4 inches. At a 2-inch spacing, 70 to 80 percent of the observers could detect turn signals adjacent to a DRL of 2,600 candela. At the higher DRL intensities, only 10 to 25 percent of the observers could detect the turn signals (which were masked almost equally, whether of 250 or 500 candela). However, about 80 to 90 percent of the observers saw the 250 candela turn signal at a 4-inch spacing. This demonstration suggests that spacing is effective, and that an increase in turn signal brightness does not compensate for inadequate spacing. Thus, GM's request for the agency not to adopt a spacing requirement does not appear to be in the interest of safety if DRLs substantially brighter than 2,600 candela are permitted. The alternative of brighter (500 candela) turn signals does not resolve the issue. The only effective alternative to prevent turn signal masking would be to extinguish the DRLs during signaling. Therefore, the final rule adopts the proposed 4-inch minimum spacing requirement, with its exception of temporary DRL deactivation. However, the 4-inch spacing requirement will continue to apply even if a higher candela turn signal is used.

E. Lens Marking

Under Notice 1, there would have been no requirement to identify the lamps used as DRLs. However, in commenting on that proposal, States asked for a lens marking requirement. In their view, State enforcement and vehicle inspection officials would be unable to distinguish between legal and illegal lamps and lamp combinations in the absence of marking. NHTSA tentatively concluded that those arguments had merit, and, further, that resolution of preemption questions would be assisted by a clear designation of the lamps used as DRLs. Under Notice 4, the agency proposed that these lamps would be marked "DRL" in letters not less than 4 mm high. A lamp that optically combines a DRL with a headlamp would be excluded from this requirement.

GM and Ford suggested that the lamps be marked with the SAE identification code, "YZ". To be consistent with the marking procedure specified in the SAE specification on marking of lighting equipment, SAE J759, GM also requested that the size of the lettering be 3 mm. The agency has adopted the latter suggestion in the final rule, but is requiring the "DRL" mark. The SAE specifications and Federal ones differ. To adopt the SAE designation would be inaccurate and confusing because it would signify adoption of the SAE requirements, instead of the different ones that NHTSA is promulgating.

Other Issues on Which Comment Was Requested or Received

The agency proposed that DRLs be activated when the transmission is in any position other than "park" or "neutral", and deactivated when the headlamp control is in the "headlamp on" position. Ford, Mack, Hino, and VW requested that the wording be compatible if not identical to the Canadian requirement. After consideration of the comments, and because the rule does not mandate DRLs, NHTSA has decided to adopt a final rule that is more flexible than either the Canadian requirement or the one that NHTSA originally proposed. It simply requires automatic activation of the system under circumstances to be determined by the vehicle manufacturer, e.g., when the transmission is in any position other than park or neutral, as NHTSA

originally proposed, or operation of the engine without operation of the headlamp switch, the Canadian requirement. The DRL would be deactivated when the headlamp control is in any "on" position, and as otherwise determined by the vehicle manufacturer, such as deactivation of the engine.

Standard No. 108 presently requires the taillamps and side marker lamps to be activated simultaneously with the headlamps. The question arises whether, when a DRL is optically combined with a headlamp, the taillamps and side marker lamps must also be activated when the DRL is. Since there is a fuel economy penalty associated with side and rear lamp use, it is possible that manufacturers combining DRLs with headlamps will not wish to activate simultaneously the side and rear lamps. Further, data exist from some studies conducted on high mounted stop lamps that indicate a negative safety effect can exist on the vehicle's required pair of lower mounted stop lamps when the taillamps are activated. This occurred because the stop lamps were not as readily perceived on some cars when the taillamps were on during the day.

NHTSA requested comments on whether a prohibition against activation of the taillamps and side marker lamps is appropriate when a DRL is optically combined with a headlamp. Notice 4 proposed that the use of side and rear lamps with the DRL be a manufacturer's option. Chrysler and VW concurred with allowance as an option. GM was concerned lest the use become a requirement, a concern also of West Virginia in response to Notice 1. Michigan in its comment to Notice 1, on the other hand, favors simultaneous activation of the taillamps with DRLs so that the rear of the vehicle will be marked in the event that headlamps are not activated during periods in which visibility is reduced. PACCAR recommended that taillamps not be used with DRLs to avoid confusion with stop lamps. After reviewing the comments, the agency finds no compelling reason to prohibit the use of side and rear lamps with DRLs.

NHTSA was also concerned about the possible increases in rear crashes from the effect of daytime taillamp operation upon the efficacy of the stop lamp signal. The presence of the CHMSL ought to provide a distinguishable signal even if the taillamps and other stop lamps are combined in the same lamp housing. However, the NHTSA Report "An Evaluation of Center High Mounted Stoplamps" (DOT–HS–807442) showed that the greatest accident reduction benefit occurred during daylight (a 20 percent reduction, compared with an 8 percent reduction during dusk, nighttime, and dawn). The CHMSL may provide greater benefits when the taillamps are off. Thus, NHTSA requested that commenters address the issue of whether daytime taillamp operation could also lessen the effectiveness of the center stop lamp.

Commenters did not address this issue. NHTSA assumes that because the center highmounted stop lamp is dedicated to a single function, while a stop and taillamp may be combined in a single housing, the center highmounted stop lamp will not be masked by taillamp operation. Beginning September 1, 1993, all new motor vehicles with a GVWR of 10,000 pounds or less will be equipped with the third stop lamp which mitigates against any long term masking problem concerning the other two stop lamps. NHTSA does not believe that larger trucks without the center lamp are likely to be designed so that the rear lamps are activated during DRL operation because of high maintenance costs. For the foregoing reasons, NHTSA has found no safety need to prohibit manufacturers from simultaneous activation of DRLs and taillamps.

The rule indirectly affects States which now have or are considering enacting laws to require operation of the headlamps when the windshield wipers are activated. Some operators of vehicles with DRLs may not, because of the operation of their DRLs, activate the headlamp switch when the wipers are activated. The intent of these laws is to improve vehicle detection in low light levels, an intent that may be fulfilled by DRLs. NHTSA wants to encourage States to allow DRLs as an alternative to headlamps in their wiper use laws. However, this rule does not change normal headlamp functioning. Drivers can still use the master headlamp switch to actuate the headlamps when state laws or driver vision requires it.

Finally, this rule will ensure that DRLs are allowed on vehicles throughout the United States. This will afford an opportunity to evaluate DRL performance under the broad geographic and road conditions that exist throughout the country. However, past DRL studies indicate that unless evaluation studies are carefully controlled, the results are likely to be misleading or inconclusive. NHTSA is interested in evaluating the effectiveness of DRLs in the U.S. and requested that commenters submit suggestions as to how this might best be accomplished.

GM believes that the most effective study can be accomplished through the implementation of a harmonized rule between the U.S. and Canada. In its opinion, this would allow a data base of a large volume of vehicles all meeting the same requirements. However, the suggestion contained no specifics, and no commenter offered more than cursory thoughts on how an evaluation might be done. NHTSA is interested in the ability of manufacturers to identify DRL-equipped vehicles, and suggests that such information be available, at least for make and model of vehicles if it is standard equipment, or by VIN if installed specially, such as on fleet purchases.

GM, Ford, and MVMA stated that the NPRM was not consistent with the goal of international harmonization of regulations within the North American Free Trade Agreement. NHTSA has taken this into account in fashioning the final rule. Harmonization does not require that regulations be identical. The final rule permits a wide range of Canadian DRLs to be used, and establishes a window of harmonization that permits a common design to meet the requirement of both countries.

IIHS commented that DRLs should not be limited to newly manufactured vehicles, and it urged that Standard No. 108 apply to aftermarket DRLs as well. Since the agency is not mandating DRLs, it had given no thought to issues of retrofit, and, in any event, the subject was beyond the scope of the NPRM and not a part of the petition upon which the rulemaking was based.

NHTSA does not believe that the lack of a regulation covering vehicles-in-use that were originally manufactured without DRLs will result in aftermarket DRLs that are contrary to the final rule. State lighting laws for vehicles-in-use are generally identical to Standard No. 108's requirements for new vehicles.

This final rule does not have any retroactive effect. Under 15 U.S.C. 1392(d), whenever a Federal motor vehicle safety standard is in effect, a state may not adopt or maintain a safety standard applicable to the same aspect of performance which is not identical to the Federal standard. 15 U.S.C. 1394 sets forth a procedure for judicial review of final rules establishing, amending or revoking Federal motor vehicle safety standards. That section does not require submission of a petition for reconsideration or other administrative proceedings before parties may file suit in court.

Shift to Expression of Measurements in Metrics

In implementation of the Department's policy to use the international metric system wherever possible in rulemakings, the values that are adopted are expressed in metrics. This shift will result temporarily in Standard No. 108 using the conventional system of measurement in some sections and the metric system in others. However, eventually, Standard No. 108 will be converted entirely to metric terms, in accordance with a NHTSA timetable.

Rulemaking Analyses

Executive Order 12291 (Federal Regulation) and DOT Regulatory Policies and Procedures

NHTSA has considered the economic impacts of this rule and has made a determination that it is not major within the meaning of E.O. 12291 nor significant under Department of Transportation policies and procedures. The rule is not mandatory upon persons otherwise regulated by Standard No. 108, therefore there is no cost impact upon any manufacturer who does not choose to offer a DRL. NHTSA has no information on whether manufacturers other than GM will avail themselves of the option. Because DRL's are not required, any cost from implementing them will be at the manufacturer's choice. There may be a small incremental increase over some standard Canadian DRL models for the purpose of limiting possibly negative safety effects, but NHTSA has not quantified these costs as DRL's are not required. Therefore, preparation of a full regulatory evaluation is not warranted.

National Environmental Policy Act

NHTSA has analyzed this rule for the purposes of the National Environmental Policy Act. It will not have a significant effect upon the environment because there is no requirement that a manufacturer provide DRLs. As noted previously in this notice, there could be a fuel economy penalty of up to one quarter mile per gallon, depending on the type of DRL.

Regulatory Flexibility Act

The agency has also considered the impacts of this rule in relation to the Regulatory Flexibility Act. I certify that this rule will not have a significant economic impact upon a substantial number of small entities, because its adoption will not establish a mandatory requirement on regulated persons. Further, the rule will not affect the price of vehicles purchased by small jurisdictions and organizations. Accordingly, no regulatory flexibility analysis has been prepared.

Executive Order 12612 (Federalism)

This rule has also been analyzed in accordance with the principles and criteria contained in Executive Order 12612, and NHTSA has determined that it does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

List of Subjects in 49 CFR Part 571

Imports, Motor vehicle safety, Motor vehicles.

PART 571—[AMENDED]

§ 571.108 [Amended]

In consideration of the foregoing, 49 CFR 571.108, Motor Vehicle Safety Standard No. 108, *Lamps, Reflective Devices, and Associated Equipment* is amended as follows:

1. The authority citation for part 571 continues to read as follows:

Authority: 15 U.S.C. 1392, 1401, 1403, 1407; delegation of authority at 49 CFR 1.50.

2. Paragraph S5.5.3 is revised to read as follows:

S5.5.3 The taillamps on each vehicle shall be activated when the headlamps are activated in a steady-burning state, but need not be activated if the headlamps are activated at less than full intensity as permitted by paragraph S5.5.11(a).

3. New paragraph S5.5.11 is added to read as follows:

S5.5.11(a) Any pair of lamps on the front of a passenger car, multipurpose passenger vehicle, truck, or bus, whether or not required by this standard, other than parking lamps or fog lamps, may be wired to be automatically activated, as determined by the manufacturer of the vehicle, in a steady burning state as daytime running lamps (DRLs) and to be automatically deactivated when the headlamp control is in any "on" position, and as otherwise determined by the manufacturer of the vehicle, provided that each such lamp:

(1) Has a luminous intensity not less than 500 candela at test point H–V, nor more than 3,000 candela at any location in the beam, when tested in accordance with Section S11 of this standard, unless it is:

(i) A lower beam headlamp intended to operate as a DRL at full voltage, or at a voltage lower than used to operate it as a lower beam headlamp; or

(ii) An upper beam headlamp intended to operate as a DRL, whose luminous intensity at test point H–V is not more than 7,000 candela, and which is mounted not higher than 864 mm above the road surface as measured from the center of the lamp with the vehicle at curb weight;

(2) Is permanently marked "DRL" on its lens in letters not less than 3 mm high, unless it is optically combined with a headlamp;

(3) Is designed to provide the same color as the other lamp in the pair, and that is one of the following colors as defined in SAE Standard J578 MAY88: White, white to yellow, white to selective yellow, selective yellow, or yellow;

(4) If not optically combined with a turn signal lamp, is located so that the distance from the edge of the illuminated surface of its lens to the optical axis (filament center) of the nearest turn signal lamp is not less than 100 mm, unless its luminous intensity as a DRL is not more than 2,600 candela at any location in the beam, or unless it is deactivated when the turn signal lamp is activated; and

(5) If optically combined with a turn signal lamp, is automatically deactivated as a DRL when the turn signal lamp or hazard warning lamp is activated, and automatically reactivated as a DRL when the turn signal lamp or hazard warning lamp is deactivated.

(b) Any pair of lamps that are not required by this standard and are not optically combined with any lamps that are required by this standard, and which are used as DRLs to fulfill the specifications of S5.5.11(a), shall be mounted at the same height, which shall be not more than 1.067 m above the road surface measured from the center of the lamp on the vehicle at curb weight, and shall be symmetrically disposed about the vertical centerline of the vehicle.

4. New paragraph S11 is added to read as follows:

S11. *Photometric Test.* A lamp that is wired in accordance with paragraph S5.5.11 of this standard, shall be tested for compliance with S5.5.11(a)(1) in accordance with the test method specified for photometric testing in SAE Standard J575 DEC88 when a test voltage of 12.8V +/20 mV is applied to the input terminals of the lamp switch module or voltage-reducing equipment, whichever is closer to the electrical source on the vehicle. The test distance from the lamp to the photometer shall be not less than 18.3 m, if the lamp is optically combined with a headlamp, or is a separate lamp, and not less than 3 m, if the lamp is optically combined with a lamp, other than a headlamp, that is required by this standard.

Issued on: January 6, 1993.

Marion C. Blakey,

Administrator.

[FR Doc. 93–531 Filed 1–8–93; 8:45 am]

BILLING CODE 4910-13-M

Proposed Rules

Federal Register
Vol. 58, No. 6
Monday, January 11, 1993

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

OFFICE OF PERSONNEL MANAGEMENT

5 CFR Part 410

RIN 3206–AF05

Training

AGENCY: Office of Personnel Management.

ACTION: Proposed rulemaking.

SUMMARY: The Office of Personnel Management (OPM) is proposing to amend its regulations governing the training of Federal employees in areas described in OPM's Memorandum for Heads of Departments and Independent Agencies, January 10, 1992, Subject: Human Resources Development Policy Initiatives. The Policy Initiatives outline a series of actions to strengthen human resources development in the Federal Government. Federal agencies are increasingly dependent on the skills and capabilities of their workforce to enhance productivity and ensure quality service to the American public. The Policy Initiatives provide broad direction and support to agencies in the management of training resources and programs. The proposed regulatory change is seen as a key element in building responsive, cost-effective, and sustained human resource development programs in Federal agencies. Regulations on training needs assessment will require each agency to establish a process that systematically links its training and development plans and resources to the agency's mission, strategic plans, performance goals, and priorities.

DATES: Written comments will be considered if received no later than February 10, 1993.

ADDRESSES: Send or deliver written comments to Dona Wolf, Director, Human Resources Development Group, U.S. Office of Personnel Management, room 5554, 1900 E Street, NW., Washington, DC 20415.

FOR FURTHER INFORMATION CONTACT: Barbara Smith, (202) 376–6804.

SUPPLEMENTARY INFORMATION: The major objective of human resource management in the Federal Government is to attract, develop, and retain a quality, balanced workforce. In its leadership capacity, OPM, in partnership with the agencies, has developed Human Resources Development Policy Initiatives as part of its plan to address this important objective. The initiatives outline critical areas for policy direction and program guidance and focus on a planned, balanced, and continuous approach to the growth and development of Government employees at all levels. In accordance with its authority under 5 U.S.C. 4118, OPM plans to issue regulatory changes as described below.

Training Needs Assessment

OPM proposes to amend its regulations in subpart B of part 410, Determining Training Needs. Needs assessment is the critical first step in a systematic approach for developing plans and programs designed to improve organizational and individual performance. The well-planned and timely assessment of needs ensures that organizational training and development resources are committed to the highest priority needs and provides the most cost effective basis for an agency's expenditure of training dollars.

Through extensive studies, OPM has found that training needs assessment practices vary widely from agency to agency. Some have very sophisticated needs assessment processes, encompassing formal task analyses of key occupations followed by systematic comparisons of employee skill levels to occupational requirements, while other agencies assess needs randomly and haphazardly. Some agencies assess employee needs on an annual basis, while others assess needs only sporadically. The variations and inconsistencies in needs assessment practices are further documented by the Volcker Commission Report, Leadership for America: Rebuilding the Public Service (Washington 1989). The Commission found that at both the career and non-career levels, training is frequently ad hoc and self initiated. Further, the Commission found agencies are not certain what they should train for (short- or long-term), which employees should receive the greatest training emphasis (entry, mid- or senior-level), or when or how often employees need additional education. The Commission also found that career paths are not well planned or designed and, "* * * with a few exceptions, most Federal training is voluntary, individually focused, and job-specific and bears little discernible relation to major agency objectives and missions. Nor is training tied to any performance goals, leaving agencies unable to justify costs in an era of tight budgets."

Based on these findings and the results of its studies on practices in both the private and public sectors, OPM proposes to regulate needs assessment to ensure that agency practices are comprehensive, uniform, and ongoing. The regulations will increase the likelihood that budget and program resources committed to training relate directly to agency mission and performance priorities. Needs assessment based on the identification of agency mission needs and critical occupational and individual performance requirements can help agencies eliminate redundant training efforts, substantially reduce the unnecessary expenditure of training dollars, and assist managers in identifying performance requirements that can best be satisfied by training and other developmental strategies.

The proposed regulations will require agencies to describe desired levels of organizational, occupational, and individual performance. Through its needs assessment process, an agency will determine the difference between actual and desired performance levels. If a gap exists, an agency will identify the underlying cause(s) for the difference. If training is determined to be appropriate, an agency will use information furnished by the needs assessment to identify who needs training and when and how it can best be provided.

The regulations propose a systematic approach to planning career development strategies for Government employees. They focus on the use of training and other development to maintain and improve organizational, occupational, and individual performance. Further, the regulations reflect the importance of a well-trained, fully developed, and balanced workforce in which needs are assessed fairly and equitably for all employees.

To assist agencies in implementing these regulations, OPM will prepare

guidance through the Federal Personnel Manual Chapter 410 (Training) that illustrates performance models, best practices, and useful needs assessment techniques and tools.

Other Development

The proposed regulations provide for consideration of developmental options (e.g., apprenticeships, reassignments, details, rotational assignments, etc.) in determinations covered by subparts B and C of part 410. This reflects OPM's view that these options should be considered in establishing priorities for meeting developmental needs. In some situations, a developmental option could be a more appropriate mechanism for skills development and less costly than formal training.

Training of Persons With Disabilities

The proposed regulations insert a reference to "persons with disabilities" in the sections dealing with "using needs assessment to manage human resources" and "selection and assignments" to ensure that agencies' procedures provide safeguards against unjustified denial of developmental opportunities for persons with disabilities.

E.O. 12291, Federal Regulation

I have determined that this is not a major rule as defined in E.O. 12291, Federal Regulation.

Regulatory Flexibility Act

I certify that these regulations will not have significant economic impact on a substantial number of small entities because they affect only Federal employees and agencies.

List of Subjects in 5 CFR Part 410

Authority delegation, Education, Government employees, Manpower training programs, Personnel Management Office.

Office of Personnel Management.

Douglas A. Brook,

Acting Director.

Accordingly, the Office of Personnel Management proposes to amend 5 CFR part 410 as follows:

PART 410—TRAINING

1. The authority citation for part 410 continues to read as follows:

Authority: 5 U.S.C. 4101, *et seq.*; E.O. 11348, 3 CFR, 1967 Comp., p. 275. § 410.503 also issued under 5 U.S.C. 5364. § 410.506, § 410.511, and § 410.602 also issued under 5 U.S.C. 1104. § 410.902 also issued under 42 U.S.C. 4746.

2. Subpart B, consisting of § § 410.201 and 410.202, is revised to read as follows:

Subpart B—Planning for Human Resource Development

Sec.

410.201 Assessment of needs.

410.202 Using needs assessment to manage human resources and plan human resource development programs.

Subpart B—Planning for Human Resource Development

§ 410.201 Assessment of needs.

(a) *General.* To prepare human resources to accomplish agency goals and program objectives effectively and efficiently, the head of an agency shall establish and maintain a system to assess training and other developmental needs and set priorities for meeting identified needs. Training needs assessment shall be an ongoing activity and incorporated within the agency's overall human resources planning process. Assessing training needs is a collaborative effort requiring the support and involvement of agency management. Agency policies on conducting needs assessment shall be set forth in writing and incorporated into policies established under § 410.301(a) of this part.

(b) *Needs Assessment System.* In conducting the reviews of training needs required by section 4113 of title 5, United States Code, and by Executive Order 11348, an agency shall identify training and other developmental needs using the criteria in paragraphs (c), (d), (e), and (f) of this section.

(1) Organizational assessment will identify broad priorities and objectives established to maintain and improve the performance of the agency and its work units. Organizational assessment ensures that the budget and program resources committed to training and other development will directly support the mission, goals, and performance requirements of the agency.

(2) Occupational assessment will identify short- and long-term job requirements that are essential to achieve operational goals and objectives for each major occupation within the agency including executive, managerial, and supervisory positions.

(3) Individual assessment will identify particular knowledge, skills, and abilities required of employees to perform their jobs. Individual employee needs will be assessed to ensure professional growth and development of employees within career paths, particularly during periods of organizational and technological change to maintain desired levels of performance. At a minimum, needs of individuals will be assessed at critical career stages, including:

(i) Initial entry to the agency;

(ii) Progression from one level of job responsibility to another within a career path, as from entry to journey level to supervisory level; and

(iii) Transition to a new career or job as from one occupation to another, technical expert to team leader, supervisor to manager, and manager to executive.

(d) *Performance Requirements.* Needs assessment will focus on the required or desired performance of the agency, the organizational unit, or the individuals being assessed. Needs assessment will be conducted to determine the difference between required or desired and actual performance levels. The agency will determine if the required or desired level of performance should be attained through training or through other methods, such as modifying systems and procedures, changing working conditions, or improving communications.

(e) *Needs Assessment Planning.* In planning and conducting needs assessments, an agency shall design and develop an assessment plan that:

(1) Identifies the goal, purpose, and level (organizational, occupational, or individual) of the particular assessment;

(2) Uses relevant documents such as productivity reports, work studies, evaluations, trend analyses, and other data sources, including needs assessment instruments, to provide accurate and reliable information on organizational, occupational, and individual performance; and

(3) Incorporates, as needed, other systems to retrieve information on organizational, occupational, and individual performance such as performance appraisal processes, succession planning strategies, and career planning systems.

(f) *Management Involvement.* Managers and supervisors will actively support the agency's needs assessment process. Management actions shall include setting human resources goals, establishing training and other development priorities, making decisions about the investment of resources and assessing the performance of individuals and occupational groups.

(g) *Needs Assessment Implementation and Evaluation.* At least annually, an agency shall:

(1) Analyze findings on new or previously identified needs to:

(i) Assure they are accurate and provide reliable information on the present and projected critical skill

requirements of the organization and individuals; and

(ii) Determine whether the findings are being used effectively by the agency to close identified gaps between desired and actual levels of performance assessed for the organization, occupational groups and individual employees; and

(2) Analyze the effectiveness and efficiency of their documented needs assessment system and procedures to determine:

(i) If they generate relevant information;

(ii) If they are practical to conduct; and

(iii) How needs assessment findings are used by the agency, including how they are used in decisions to allocate agency training resources.

§ 410.202 Using needs assessment to manage human resources and plan human resource development programs.

(a) An agency shall evaluate information derived from organizational, occupational, and individual assessments and use these findings to make decisions on training resource allocations and plan human resources development programs.

(b) Organizational assessment findings shall be used by agency officials as the basis for:

(1) Establishing human resources development goals and priorities;

(2) Integrating human resources development planning with work planning, budgeting, and other personnel management systems;

(3) Making short- and long-term decisions on investment of resources to plan for training and other developmental activities within the agency;

(4) Designing, developing, conducting, and evaluating training, new employee orientation programs, and other development programs and activities for the agency through internal and external resources; and

(5) Assessing agency plans to ensure consistency with the merit system principles set forth in 5 U.S.C. 2301(b)(1) and (2), taking into consideration the need to maintain a diversified workforce in which women, minorities, and persons with disabilities are appropriately represented and developed in the agency.

(c) Occupational assessment findings shall be used as the basis for:

(1) Evaluating workforce trends and occupational forecasts to determine what short- and long-term strategies will be undertaken to attain the future skill requirements;

(2) Developing strategies to address recruiting and retention issues for mission-critical occupations;

(3) Identifying and tracking career paths, where feasible, and the training needs of employees on those paths, including needs for continuing technical/professional development, based on an analysis of the occupation's tasks and an identification of the competencies associated with various stages of advancement in that occupation;

(4) Establishing training and other development programs to meet the knowledge and skill needs of employees in key occupations; and

(5) Ensuring that budget and program resources allocated for mission-related training and other development in key occupations are supportive of organizational or agencywide priorities.

(d) Individual assessment findings shall be used as the basis for:

(1) Developing plans for career and personal growth and to improve individual performance;

(2) Identifying areas where training and other development could improve the performance of an employee rated at a level below "Fully Successful" or enhance the competencies of an employee already performing at a "Fully Successful" or higher level to achieve the highest level of proficiency and to help prepare for future assignments on his/her career path or for occupational change.

(3) Selecting training and other developmental activities for employees; and

(4) Ensuring that resources allocated for individual training and other development are linked to organizational human resources development priorities.

3. Subpart C, consisting of §§ 410.301 through 410.304, is revised to read as follows:

Subpart C—Establishing human resource development programs

Sec.

410.301 Scope and general conduct of programs.
410.302 Selection and assignment of employees for development.
410.303 Utilization of trainees.
410.304 Evaluation of training.

Subpart C—Establishing Human Resource Development Programs

§ 410.301 Scope and general conduct of programs.

(a) The head of an agency shall determine the policies which are to govern the development of the agency's workforce. These policies shall be set forth in writing and include a statement of the broad purposes for which training and other development will be given and of the assignment of responsibilities for seeing that these purposes are achieved.

(b) The head of an agency also shall take such administrative action as is necessary to assure that:

(1) Plans and programs are developed to meet the short- and long-range training and other developmental needs within the agency;

(2) Priorities are established for training and other developmental programs of the agency;

(3) Provision is made for the use of funds and staff hours in accordance with established priorities for training and other developmental programs of the agency;

(4) Employee self-development is fostered through a work environment in which self-development is encouraged, self-study materials are reasonably available, and self-initiated improvement in performance is recognized; and

(5) Information with respect to the general conduct of the training program of the agency is availabled to enable the Office of Personnel Management, the President, and Congress to discharge their respective responsibilities under chapter 41 of title 5, United States Code.

(c) Training programs established by the agencies under chapter 41 of title 5, United States Code, shall to the maximum extent feasible:

(1) Be based on short- or long-range needs, existing or reasonably foreseeable;

(2) Meet as many of these needs as possible, with priorities considered;

(3) Use work assignment flexibility to provide experience to promote employee growth for the purpose of increasing the quality and quantity of work produced; and

(4) Be integrated with other personnel management and operating activities.

(d) As provided in subsection (b) of section 4103 of title 5, United States Code, an agency may train any employee of the agency to prepare the employee for placement in another agency when the following conditions are met:

(1) The head of the agency must determine that the employee will otherwise be separated under conditions which would entitle the employee to severance pay under section 5595 of title 5, United States Code;

(2) Before undertaking any training under this section, the head of the agency shall obtain verification from the Office of Personnel Management that there exists a reasonable expectation of placement in another agency; and

(3) In selecting an employee for training under this section, the head of the agency shall consider:

(i) The extent to which the current skills, knowledge, and abilities of the employee may be used in the new position;

(ii) The employee's capability to learn skills and acquire knowledge and abilities needed in the new position; and

(iii) The benefits to the Government which would result from retaining the employee in the Federal service.

§ 410.302 Selection and assignment of employees for development.

(a)(1) Except as provided by paragraph (a)(2) of this section, an agency must follow its merit promotion procedures when selecting a career or career-conditional employee for training or other development which is:

(i) Part of an authorized training agreement;

(ii) Part of a promotion program; or

(iii) Required before an employee may be considered for a promotion.

(2) Paragraph (a)(1) of this section does not apply if:

(i) The agency's merit promotion procedures have already been applied; or

(ii) The development is associated with an action not covered by or excepted from those procedures.

(b) With respect to selection and assignment of employees to training by, in, or through non-Government facilities, the head of an agency shall provide that each assignment of an employee who is stationed within the continental limits of the United States to training outside these limits be approved by a specifically designated official at the headquarters level of the agency.

(c) The head of an agency shall prescribe such procedures as are necessary to assure that the selection of employees for development is made without regard to race, color, religion, sex, national origin, age, disability, or other factors unrelated to the need for employee development.

§ 410.303 Utilization of trainees.

An agency, in effecting position changes, shall consider significant training and other developmental activities undertaken by employees.

§ 410.304 Evaluation of training.

An agency shall evaluate the results and effects of training programs and other developmental activities in such manner and with such frequency as the agency head considers appropriate.

[FR Doc. 93–397 Filed 1–8–93; 8:45 am]

BILLING CODE [illegible]

DEPARTMENT OF AGRICULTURE

Federal Grain Inspection Service

7 CFR Part 68

United States Standards for Rice

AGENCY: Federal Grain Inspection Service, USDA.[1]

ACTION: Proposed rule.

SUMMARY: In compliance with the requirements for periodic review of regulations, the Federal Grain Inspection Service (FGIS) is proposing to revise the United States Standards for Rice. Specifically, FGIS proposes to revise the United States Standards for Rough Rice, Brown Rice for Processing, and Milled Rice by establishing a special grade for aromatic (scented) rice and eliminating the requirement that rough rice or brown rice for processing must contain more than 25 percent of whole kernels in order to be classed as Long grain, Medium grain, Short grain, or Mixed rough rice or brown rice for processing.

DATES: Comments must be submitted on or before April 12, 1993.

ADDRESSES: Written comments must be submitted to George Wollam, FGIS, USDA, Room 0632 South Building, P.O. Box 96454, Washington, DC, 20090–6454; FAX (202) 720–4628. All comments received will be made available for public inspection in Room 0632 USDA South Building, 1400 Independence Avenue SW., Washington, DC, during regular business hours (7 CFR 1.27(b)).

FOR FURTHER INFORMATION CONTACT: George Wollam, address as above, telephone (202) 720–0292.

SUPPLEMENTARY INFORMATION:

Executive Order 12291

This proposed rule has been issued in conformance with Executive Order 12291 and Departmental Regulation 1512–1. This action has been classified as nonmajor because it does not meet the criteria for a major regulation established in the Order.

Executive Order 12778

This proposed rule has been reviewed under Executive Order 12778, Civil Justice Reform. This action is not intended to have retroactive effect. This proposed rule will not preempt any State or local laws, regulations, or policies, unless they present an irreconcilable conflict with this rule. There are no administrative procedures which must be exhausted prior to any judicial challenge to the provisions of this rule.

Regulatory Flexibility Act Certification

John C. Foltz, Administrator, FGIS, has determined that this proposed rule will not have a significant economic impact on a substantial number of small entities because those persons who apply the standards and most users of the inspection services do not meet the requirements for small entities as defined in the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). Further, the standards are applied equally to all entities.

Review of Standards

On January 22, 1992, FGIS published in the **Federal Register** (57 FR 2482) a request for public comment on the review of the United States Standards for Rice. The objective of the review is to ensure that the standards continue to serve the needs of the marketplace to the greatest extent possible. In keeping with this objective, FGIS requested comments on the need for revising various sections of the standards, the potential for improvements, and language clarity. Specifically, FGIS has focused on reviewing the need to:

1. Establish standards for edible brown rice,

2. Establish a special grade for aromatic rice,

3. Increase the limits for broken kernels removed by a 5 plate for U.S. Nos. 1 and 2 milled rice,

4. Eliminate the class Screenings milled rice,

5. Revise the definitions of the classes of rough rice by eliminating the requirement that these classes must contain more than 25 percent whole kernels, and

6. Revise the definitions of the classes Second Head, Screenings, and Brewers milled rice by eliminating the southern production criteria and adopting the western production criteria for rice grown in all areas of production.

Interested parties were invited to participate in the rulemaking process by submitting written comments and/or recommendations on the suggested changes to the official standards. During the 90-day comment period, a total of nine comments were received from private companies, governmental and educational organizations, and groups representing rice growers and millers.

[1] The authority to exercise the functions of the Secretary of Agriculture contained in the Agricultural Marketing Act of 1946, as amended (7 U.S.C. 1621–1627), concerning inspection and standardization activities related to grain and similar commodities and products thereof has been delegated to the Administrator, Federal Grain Inspection Service (7 U.S.C. 75a; 7 CFR 68.5).

Establishing Standards for Edible Brown Rice

Presently, there are no U.S. standards for edible brown rice; i.e., brown rice that is intended to be consumed without being milled. The current U.S. Standards for Brown Rice for Processing were developed solely for brown rice intended to be processed into milled rice. Most edible brown rice is marketed on private specifications. For this reason, FGIS sought to determine whether there was a need to develop U.S. standards specifically for edible brown rice.

Four groups representing rice growers, millers, and processors commented on the need to establish standards for edible brown rice. It was the view of two of those groups that standards for edible brown rice are not needed. One other group commented that they would not oppose standards for edible brown rice, "but question the industry's desire or need for edible brown rice standards at this time." Only one commenter expressed any support for the establishment of standards provided that "standards do not allow the inclusion of white milled broken rice."

From the comments received, FGIS has determined that a majority of the market would not use U.S. standards for edible brown rice if they were available. Consequently, FGIS will not propose establishing standards for edible brown rice at this time.

Establishing a Special Grade for Aromatic Rice

The amount of aromatic or scented rice produced in the United States has grown steadily in the last decade, as has the demand for relevant standards of quality. In response, FGIS requested comments on the need to establish a special grade for aromatic rice. The present U.S. Standards for Rough Rice, Brown Rice for Processing, and Milled Rice are being applied to aromatic rice. But, the current standards do not provide for grading or otherwise identifying such rice as "Aromatic."

Groups representing rice growers, millers, and processors commented that aromatic rice has the potential to greatly expand both production and consumption beyond current levels. Establishing a special grade for aromatic rice could facilitate this expansion and assist consumers. Therefore, FGIS, is proposing to revise the U.S. Standards for Rough Rice, Brown Rice for Processing, and Milled Rice to establish a special grade for aromatic rice.

Increasing Limits on Broken Kernels Removed by a 5 Plate

A 5 plate is a laminated metal plate with rows of perforated round holes that are 5/64 inch in diameter. "Broken kernels removed by a 5 plate" consist of very small particles of broken rice that become trapped in the plate's holes when a 50 gram sample is poured over the plate. According to the U.S. Standards for Milled Rice, the maximum limit for "broken kernels removed by a 5 plate" in U.S. Nos. 1 and 2 milled rice is 0.04 percent and 0.06 percent, respectively.

FGIS sought comments on whether the limits for "broken kernels removed by a 5 plate" should be increased to 0.1 percent for both U.S. Nos. 1 and 2 milled rice. This action would compensate for the normal variability of the scales used to determine the amount of this material in a sample. The scales used by FGIS to determine the amount of "broken kernels removed by a 5 plate" in a 50 gram sample of milled rice are accurate to plus or minus 0.02 gram. Therefore, the results of any "broken kernels removed by a 5 plate" determination may vary by as much as plus or minus 0.04 percent.

Several of the groups that commented on this suggestion expressed deep concerns about changing the current levels. These commentors felt that allowing a greater amount of small broken kernels in high-quality U.S. rice would reduce the marketability of U.S. Nos. 1 and 2 milled rice. FGIS believes that a slight increase in the limits would not have a noticeable effect on rice quality or appearance. But, FGIS is concerned that any loosening of grade limits may inadvertently harm the United States' reputation for producing and marketing high-quality rice. To avoid any such negative consequences, FGIS plans to investigate other alternatives (e.g., use more accurate scales or increase the sample size to 100 grams), rather than increasing the "broken kernels removed by a 5 plate" limit.

Eliminating the Class Screenings Milled Rice

Broken milled rice, rice that contains less than 25 percent of whole kernels, is currently classed as either Second Heads, Screenings, or Brewers milled rice, depending on the size of the broken kernels. FGIS suggested that consideration be given to eliminating the class Screenings milled rice because there was no known price discount or premium for this class of rice.

Most commenters stated that Screenings milled rice is still a viable and useful classification and that the elimination of it could have a potentially significant negative impact on trade. As a result, FGIS has determined that further review would be necessary before FGIS would propose any change in the classification of broken milled rice.

Revising the Class Definitions for Rough Rice and Brown Rice for Processing

FGIS suggested that the definitions of the classes Long grain, Medium grain, Short grain, and Mixed rough rice may need to be revised by eliminating the requirement that these classes must contain more than 25 percent whole kernels. Rough rice and brown rice for processing that contains less than 25 percent whole kernels cannot be identified by a class name. As a result, this rice cannot be graded. Milled rice, on the other hand, that contains less than 25 percent whole kernels can be identified by class name (e.g., Second Head, Screenings, or Brewers milled rice) and can be graded.

Elimination of the 25 percent whole kernel requirement for classing rough rice and brown rice for processing is supported by rice grower and miller groups who believe that this change will facilitate the marketing of rice and benefit both farmers and rice mills. Therefore, FGIS is proposing to revise the U.S. Standards for Rough Rice and Brown Rice for Processing by eliminating the requirement that rice in the classes Long grain, Medium grain, Short grain, and Mixed rough rice or brown rice for processing must contain more than 25 percent whole kernels.

Eliminating the Southern Production Criteria for Classing Second Head, Screenings, and Brewers Milled Rice

FGIS evaluated the need to revise the definitions of the classes Second Head, Screenings, and Brewers Milled Rice by eliminating the Southern production method and adopting the Western production method for rice grown in all areas. FGIS found that adopting one method for all rice would eliminate buyer confusion and provide nationwide uniformity. Also, sieves (Western production equipment) are less expensive and more portable than sizing plates (Southern production equipment).

Six groups commented on this suggestion. Two private companies and one State governmental organization supported eliminating the Southern production method and using the Western production method for all rice. But, a group that represents rice millers and two groups that represent rice

growers were strongly opposed to adopting the Western production method for rice grown in all areas. They stated that the Western production method would be costly and cumbersome for Southern mills. They also stated that "because of the shape of the kernel, Long grain does not size well on sieves. Therefore, to be tested fairly, a sizing separation using plates is needed." Long grain rice is predominately-grown in the South. There organizations also stated that there is insufficient data to support the elimination of the Southern production method and that another method should be developed that replaces both the Southern and the Western production methods. After due consideration, FGIS has determined that further review would be necessary before FGIS would propose the elimination of either the Southern or Western production methods.

Proposed Action

Based on current market needs, FGIS is proposing to revise:

1. Section 68.202(c)(1) by removing "which contains more than 25 percent of whole kernels and."
2. Section 68.202(c)(2) by removing "which contains more than 25 percent of whole kernels and."
3. Section 68.202(c)(3) by removing "which contains more than 25 percent of whole kernels and."
4. Section 68.202(c)(4) by removing "which contains more than 25 percent of whole kernels and."
5. Section 68.212 by adding a new paragraph (e), that defines aromatic rough rice.
6. Section 68.213 by adding a special grade designation for aromatic rough rice.
7. Section 68.252(d)(1) by removing "more than 25.0 percent of whole kernels of brown rice and."
8. Section 68.252(d)(2) by removing "more than 25.0 percent of whole kernels of brown rice and."
9. Section 68.252(d)(3) by removing "more than 25.0 percent of whole kernels of brown rice and."
10. Section 68.252(d)(4) by removing "more than 25.0 percent of whole kernels of brown rice and."
11. Section 68.263(d)(2) by adding a new paragraph (d), that defines aromatic brown rice for processing.
12. Section 68.264 by adding a special grade designation for aromatic brown rice for processing rice.
13. Section 68.315 by adding a new paragraph (f), that defines aromatic milled rice.
14. Section 68.316 by adding a special grade designation for aromatic milled rice.

The Department of Agriculture is committed to carrying out its statutory and regulatory mandates in a manner that best serves the public interest. Therefore, where legal discretion permits, the Department actively seeks to promulgate regulations that promote economic growth, create jobs, are minimally burdensome and are easy for the public to understand, use or comply with. In short, the Department is committed to issuing regulations that maximize net benefits to society and minimize costs imposed by those regulations. This principle is articulated in President Bush's January 28, 1992 memorandum to agency heads, and in Executive Orders 12291 and 12498. The Department applies this principle to the full extent possible, consistent with law.

The Department has developed and reviewed this regulatory proposal in accordance with these principles. Nonetheless, the Department believes that public input from all interested persons can be invaluable to ensuring that the final regulatory product is minimally burdensome and maximally efficient. Therefore, the Department specifically seeks comments and suggestions from the public regarding any less burdensome or more efficient alternative that would accomplish the purposes described in the proposal. Comments suggesting less burdensome or more efficient alternatives should be addressed to the agency as provided in this notice.

List of Subjects in 7 CFR Part 68

Administrative practice and procedures, Agricultural commodities, Rice.

For reasons set forth in the preamble, 7 CFR part 68 is proposed to be amended as follows:

PART 68—REGULATIONS AND STANDARDS FOR INSPECTION AND CERTIFICATION OF CERTAIN AGRICULTURAL COMMODITIES AND THEIR PRODUCTS

1. The authority citation for part 68 continues to read as follows:

Authority: Secs. 202–208, 60 Stat. 1087, as amended (7 U.S.C. 1621 *et seq.*).

Subpart C—United States Standards for Rough Rice

Subpart D—United States Standards for Brown Rice for Processing

Subpart E—United States Standards for Milled Rice

2. Section 68.202(c) (1) through (4) are revised to read as follows:

§ 68.202 Definition of other terms.

* * * * *

(c) * * *

(1) "Long grain rough rice" shall consist of rough rice which, after milling to a well-milled degree, contains not more than 10.0 percent of whole or broken kernels of medium or short grain rice.

(2) "Medium grain rough rice" shall consist of rough rice which, after milling to a well-milled degree, contains not more than 10.0 percent of whole or large broken kernels of long grain rice or whole kernels of short grain rice.

(3) "Short grain rough rice" shall consist of rough rice which, after milling to a well-milled degree, contains not more than 10.0 percent of whole or large broken kernels of long grain rice or whole kernels of medium grain rice.

(4) "Mixed rough rice" shall consist of rough rice which, after milling to a well-milled degree, contains more than 10.0 percent of "other types" as defined in paragraph (h) of this section.

* * * * *

3. Section 68.212(e) is added after the note to read as follows:

§ 68.212 Special grades and requirements.

* * * * *

(e) *Aromatic rough rice.* Aromatic rough rice shall be special varieties of rice (Oryza sativa L. scented) that have a distinctive and characteristic aroma; e.g., basmati and jasmine rice.

4. Section 68.213 is revised to read as follows:

§ 68.213 Special grade designation.

The grade designation for infested, parboiled, smutty, glutinous, or aromatic rough rice shall include, following the class, the word(s) "Infested," "Parboiled Light," "Parboiled," "Parboiled Dark," "Smutty," "Glutinous," or "Aromatic," as warranted, and all other information prescribed in § 68.211.

5. Section 68.252(d) (1) through (4) are revised to read as follows:

§ 68.252 Definition of other terms.

* * * * *

(d) * * *

(1) "Long grain brown rice for processing" shall consist of brown rice for processing which contains not more than 10.0 percent of whole or broken kernels of medium or short grain rice.

(2) "Medium grain brown rice for processing" shall consist of brown rice for processing which contains not more than 10.0 percent of whole or large broken kernels of long grain rice or whole kernels of short grain rice.

(3) "Short grain brown rice for processing" shall consist of brown rice for processing which contains not more than 10.0 percent of whole or large

broken kernels of long grain rice or whole kernels of medium grain rice.

(4) "Mixed brown rice for processing" shall consist of brown rice for processing which contains more than 10.0 percent of "other types" as defined in paragraph (i) of this section.

* * * * *

6. Section 68.263(d) is added after the note to read as follows:

§ 68.263 Special grades and special grade requirements.

* * * * *

(d) *Aromatic brown rice for processing.* Aromatic brown rice for processing shall be special varieties of rice (Oryza sativa L. scented) that have a distinctive and characteristic aroma; e.g., basmati and jasmine rice.

7. Section 68.264 is revised to read as follows:

§ 68.264 Special grade designation.

The grade designation for parboiled, smutty, glutinous, or aromatic brown rice for processing shall include following the class, the word(s) "Parboiled," "Smutty," "Glutinous," or "Aromatic," as warranted, and all other information prescribed in § 68.262.

8. Section 68.315(f) is added after the note to read as follows:

§ 68.315 Special grades and special grade requirements.

* * * * *

(f) *Aromatic milled rice.* Aromatic milled rice shall be special varieties of rice (Oryza sativa L. scented) that have a distinctive and characteristic aroma; e.g., basmati and jasmine rice.

9. Section 68.316 is revised to read as follows:

§ 68.316 Special grade designation.

The grade designation for coated, granulated brewers, parboiled, undermilled, glutinous, or aromatic milled rice shall include, following the class, the word(s) "Coated," "Granulated," "Parboiled Light," "Parboiled," "Parboiled Dark," "Undermilled," "Glutinous," or "Aromatic," as warranted, and all other information prescribed in § 68.314.

Dated: December 14, 1992.

John C. Foltz,

Administrator.

[FR Doc. 93–399 Filed 1–8–93; 8:45 am]

BILLING CODE 3410–EN–M

Commodity Credit Corporation

7 CFR Part 1446

RIN 0560–AC89

Peanuts

AGENCY: Commodity Credit Corporation, USDA.

ACTION: Proposed Rule.

SUMMARY: This proposed rule would amend regulations with respect to the "disaster transfer" of peanuts for pricing purposes from an additional loan pool to a quota loan pool. The proposed change would exclude any peanut poundage quota transferred to a farm under the "fall transfer" provision from the poundage quota available to that farm to effect a transfer under the "disaster transfer" provision. This change is needed to prevent the possibility of increased cost to the peanut program and related increases in the public debt. This action is necessary to provide applicable rules for 1993 through 1995 crops of peanuts with respect to transfer restrictions.

DATES: Comments must be received on or before February 10, 1993 in order to be assured of consideration.

ADDRESSES: Send comments to the Director, Tobacco and Peanuts Division, Agricultural Stabilization and Conservation Service (ASCS), United States Department of Agriculture (USDA), P.O. Box 2415, Washington, DC 20013–2415, or deliver to room 5750, South Building, 14th Street and Independence Avenue, SW., Washington, DC. All written comments received in response to this request will be made available for public inspection in room 5750, South Building, USDA, between the hours of 8:15 a.m. and 4:45 p.m., on regular workdays.

FOR FURTHER INFORMATION CONTACT: Jack S. Forlines, Deputy Director, Tobacco and Peanuts Division, ASCS, USDA, P.O. Box 2415, Washington, DC 20013–2415, telephone 202–720–0156.

SUPPLEMENTARY INFORMATION:

Executive Order 12291

This proposed rule has been reviewed under USDA procedures established in accordance with Executive Order 12291 and has been classified not major because it does not meet any of the three criteria identified under the Executive Order. This action will not have an annual effect on the economy of $100 million or more, nor will it result in major increases in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographical regions. Furthermore, it will not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of United States-based enterprises to compete with foreign-based enterprises in domestic or export markets.

Federal Assistance Program

The title and number of the Federal assistance program, as found in the Catalog of Federal Domestic Assistance, to which this proposed rule applies are: Commodity Loans and Purchases—10.051.

Regulatory Flexibility Act

It has been determined that the Regulatory Flexibility Act is not applicable to this proposed rule since the Commodity Credit Corporation (CCC) and ASCS are not required by 5 U.S.C. 553 or any other provision of law to publish a notice of proposed rulemaking with respect to the subject matter of this rule.

Executive Order 12372

This program/activity is not subject to the provisions of Executive Order 12372 which requires intergovernmental consultation with State and local officials. See the notice related to 7 CFR part 3015, subpart V, published at 48 FR 29115 (June 24, 1983).

Paperwork Reduction Act

The information collection requirements contained in the regulations in 7 CFR part 1446 for the peanut price support program were approved by the Office of Management and Budget (OMB), as required by 44 U.S.C. chapter 35, and assigned OMB control numbers 0560–0006, 0560–0014, and 0560–0033. This proposed rule does not change the information collection as approved by OMB. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Department of Agriculture, Clearance Officer, OIRM, room 404W, Washington, DC 20250; and to the Office of Management and Budget, Paperwork Reduction Project (OMB #0506–0006), Washington, DC 20503.

Regulatory Reform: Less Burdensome or More Efficient Alternatives

USDA is committed to carrying out its statutory and regulatory mandates in a manner that best serves the public interest. Therefore, where legal discretion permits, USDA actively seeks to promulgate regulations that promote economic growth, create jobs, are minimally burdensome and are easy for

the public to understand, use or comply with. In short, USDA is committed to issuing regulations that maximize net benefits to society and minimize costs imposed by those regulations. This principle is articulated in President Bush's January 28, 1992, memorandum to agency heads, and in Executive Orders 12291 and 12498. USDA applies this principle to the full extent possible, consistent with law.

USDA has developed and reviewed this regulatory proposal in accordance with these principles. Nonetheless, USDA believes that public input from all interested persons can be invaluable to ensuring that the final regulatory product is minimally burdensome and maximally efficient. Therefore, USDA specifically seeks comments and suggestions from the public regarding any less burdensome or more efficient alternative that would accomplish the purposes described in the proposal. Comments suggesting less burdensome or more efficient alternatives should be addressed to the agency as provided in this Notice.

Background

Under section 358–1(b)(8)(D) of the Agricultural Adjustment Act of 1938, as amended, any increase in the farm poundage quota for a farm for a marketing year may be used during the marketing year for the transfer of additional peanuts produced on the farm to the quota loan pool for pricing purposes on such basis as the Secretary of Agriculture shall by regulation prescribe. Such transfers for pricing purposes are commonly known as "disaster transfers."

Section 1446.307 of the peanut regulations provides the conditions for approving a "disaster transfer" of Segregation 2 and Segregation 3 peanuts from an additional loan to a quota loan. Generally, such transfer may be approved to the extent the effective farm poundage quota exceeds the sum of the amount of peanuts retained on the farm for seed or other uses and the production of Segregation 1 peanuts on the farm.

The purpose of the disaster transfer is to prevent an economic disaster to the producer who has a poundage quota and plants peanuts with the expectation of marketing the peanuts as quota peanuts but, because of conditions beyond the producer's control, is prevented from marketing some of the peanuts as quota peanuts because the peanuts are graded as Segregation 2 or Segregation 3 peanuts that are ineligible for marketing as quota peanuts. The current difference between an additional loan and a quota loan is more than $500 per ton of peanuts.

Under the "fall transfer" provision of 7 CFR part 729, peanut poundage quota may be transferred to a farm by lease, owner, or operator to the extent needed to market the entire production of peanuts on the farm as quota peanuts. If the harvest of peanuts has not been completed, the quantity of peanut poundage quota that may be transferred is determined on the basis of estimated production. When peanuts are graded as Segregation 2 or Segregation 3 after a fall transfer of poundage quota has been approved, the poundage quota that has been transferred to the farm may be used to effect a disaster transfer with resulting loss to CCC. Generally, § 1446.307 of the peanut regulations permits the transfer of Segregation 2 or 3 peanuts from an additional loan to a quota loan for pricing purposes, since Segregation 2 and Segregation 3 peanuts are not eligible for a quota loan at time of marketing. Under current rules, such transfers are allowed to the extent the effective farm poundage quota exceeds the sum of peanuts retained on the farm for seed or other uses and the production of Segregation 1 peanuts on the farm, unless the producer has been indemnified for such peanuts by the Federal Crop Insurance Corporation. Except for offsets from any pool profits otherwise earned by the producer, "disaster transfers" result in a loss to CCC of $350 to $550 per ton for each ton transferred.

Permitting disaster transfers without adjustment for fall transfers provided greater flexibility to farmers and has been permitted before for that reason, subject to additional review. However, while that flexibility has value, it appears on further review that the value of that flexibility may not overweigh the potential of increased program cost and that the issue should be the subject of further comment. Accordingly, in order to allow for minimizing the potential cost of the peanut program, this proposed rule would amend § 1446.307 to limit a disaster transfer to the amount by which the poundage quota, that was in effect on the farm before the "fall transfer" of quota, is greater than the sum of peanuts retained on the farm for seed or other purposes and the production of Segregation 1 peanuts on the farm. In the event the farm has Segregation 2 or Segregation 3 peanuts, however, it may be that the farm will qualify as having undermarketings which can be carried forward.

List of Subjects in 7 CFR Part 1446

Loan programs—Agriculture, Peanuts, Price support programs, Reporting and recordkeeping requirements, Warehouses.

Accordingly, it is proposed that 7 CFR part 1446 be amended as follows:

PART 1446—PEANUTS

1. The authority citation for 7 CFR part 1446 continues to read as follows:

Authority: 7 U.S.C. 1359a, 1375, 1421 *et seq.*; 15 U.S.C. 714b and 714c.

2. In § 1446.307, paragraph (b) is revised to read as follows:

§ 1446.307 Disaster transfer of Segregation 2 or Segregation 3 peanuts from additional loan to quota loan.

* * * * *

(b) *Limitation of amount eligible for transfer.* The amount of such transfer made in accordance with this section may not exceed the effective farm poundage quota minus the sum of:

(1) Peanuts retained on the farm for seed or other uses,

(2) Production of Segregation 1 peanuts on the farm, and

(3) Amount of peanuts equal to the amount of quota transferred to the farm through a fall transfer pursuant to part 729 of this title.

* * * * *

Signed at Washington, DC, on January 5, 1993.

John A. Stevenson,

Acting Executive Vice President, Commodity Credit Corporation.

[FR Doc. 93–450 Filed 1–8–93; 8:45 am]

BILLING CODE 3410–05–M

NUCLEAR REGULATORY COMMISSION

10 CFR Parts 30, 40, 50, 70, 72

RIN 3150–AE16

Self-Guarantee as an Additional Financial Assurance Mechanism

AGENCY: Nuclear Regulatory Commission.

ACTION: Proposed rule.

SUMMARY: The Nuclear Regulatory Commission is proposing to amend its regulations for decommissioning licensed facilities to allow certain non-electric utility licensees to use self-guarantee as a means of financial assurance. The proposed rule would reduce the cost burden of financial assurance while providing NRC with sufficient assurance that decommissioning costs will be funded. This proposed rule responds to a petition for rulemaking (PRM–30–59) from General Electric Company and Westinghouse Electric Corporation.

DATES: Comment period expires March 29, 1993. Comments received after this date will be considered if it is practical to do so, but the Commission is able to assure consideration only for comments received on or before this date.

ADDRESSES: Mail written comments to: Secretary, U.S. Nuclear Regulatory Commission, Washington, DC, 20555, Attention: Docketing and Service Branch.

Deliver comments to: 11555 Rockville Pike, Rockville, Maryland, between 7:45 a.m. and 4:15 p.m. Federal workdays.

Copies of the regulatory analysis and comments received may be examined at: The NRC Public Document Room, 2120 L Street, NW. (Lower Level), Washington, DC.

FOR FURTHER INFORMATION CONTACT: Clark Prichard, Office of Nuclear Regulatory Research, U.S. Nuclear Regulatory Commission, Washington, DC 20555, telephone (301) 492–3734.

SUPPLEMENTARY INFORMATION:

Background

On September 25, 1991 (56 FR 48445), the NRC published a notice of receipt of a petition for rulemaking from the General Electric Company (GE) and the Westinghouse Electric Corporation (Westinghouse). The petitioners requested that the NRC amend its decommissioning regulations contained in 10 CFR parts 30, 40, 50, 70, and 72 to provide a means for self-guarantee of decommissioning funding costs by certain NRC licensees who meet stringent financial standards and related reporting and oversight requirements. The petitioners proposed that electric utility reactor licensees under 10 CFR part 50 not be affected by the proposals in the petition.

On June 27, 1988 (53 FR 24018), the NRC published a final rule that established general requirements for decommissioning nuclear facilities. These requirements provide assurance that licensed facilities will be decommissioned in a safe and timely manner and that adequate funds will be available for decommissioning. Under the present decommissioning regulations, licensees are permitted to provide financial assurance for decommissioning funding through prepayment, insurance, a surety bond, a letter of credit, a parent company guarantee, or for electric utilities, the establishment of an external sinking fund.

In 1990, GE and Westinghouse requested exemptions from the financial assurance requirements for decommissioning. The requested exemptions would have permitted GE and Westinghouse to demonstrate financial assurance for decommissioning by submitting a self-guarantee that otherwise met or exceeded the criteria for qualifying parent company guarantees under appendix A to 10 CFR part 30. The Commission denied the requests for exemption. Later in 1990, GE and Westinghouse each submitted a petition for reconsideration of their requests for exemption. These requests for reconsideration were also denied. However, in informing GE and Westinghouse of the denial, the Commission indicated a willingness to consider a petition for rulemaking from GE and Westinghouse.

The GE/Westinghouse petition was docketed on July 11, 1991 (PRM–30–59). The petition requested that parts 30, 40, 50, 70, and 72 be amended to allow corporate self-guarantee as an additional method of complying with financial assurance for decommissioning requirements in those parts. The petition proposed criteria for corporate self-guarantee which would assure that only very strong financial entities could qualify. The financial criteria which were proposed are:

(1) Tangible net worth of at least $1 billion.

(2) Tangible net worth at least 10 times the current decommissioning cost estimate, or the current amount required if certification is used.

(3) Assets located in the United States amounting to at least 90 percent of total assets or at least 10 times the current decommissioning cost estimate, or the current amount required if certification is used.

(4) A current bond rating of AAA, AA, or A as issued by Standard and Poors (S&P), or Aaa, Aa, or A as issued by Moodys.

A number of procedural requirements were also proposed:

(1) The company must have at least one class of equity securities registered under the Securities Exchange Act of 1934.

(2) The company will provide the Commission with copies of all reports filed with the Securities and Exchange Commission under section 13 of the Securities Exchange Act of 1934.

(3) The company's independent certified public accountant must compare the data used by the company in the financial test with the company's independently audited yearend financial statements.

(4) The company must repeat passage of the test within 90 days after the close of each succeeding fiscal year.

(5) The company must notify NRC within 90 days of any matters coming to the attention of the auditor that cause the auditor to believe that the data specified in the financial test should be adjusted and that the company no longer passes the test.

The self-guarantee would be available only for an applicant or licensee having no parent company holding majority control of its voting stock.

Basis for Petition

The petitioners believed that they have been adversely and unreasonably affected by limitations in the current decommissioning regulations. Companies such as the petitioners are unable to guarantee decommissioning funding if they themselves are the licensee. However, relatively weaker financial institutions, such as banks, insurance companies, and savings and loans, are permitted to guarantee decommissioning funding for licensees without providing any evidence of financial strength.

Furthermore, licensees without the financial strength of the petitioners may provide qualifying parent company guarantees solely because these parent companies are legal entities distinct from the subsidiary licensees whose decommissioning funding they guarantee.

The petitioners asserted that the lack of an internal decommissioning funding method imposes unwarranted compliance costs upon them. The current regulations compel the petitioners to either restructure their licensed activities into less financially secure subsidiaries for which they could then provide a parent company guarantee, or to purchase outside financial assurance.

Public Comments

The Commission received five comment letters in response to the publication of the notice of receipt of the petition. Most of the letters supported a revision of the Commission's regulations to allow self guarantee. Three large materials licensees supported self guarantee, although they favored less stringent financial criteria for self guarantee so that a wider range of licensees could qualify to use self guarantee. One large materials licensee prefers that the tangible net worth requirement should be ten times the estimated decommissioning costs, or in the case of licensees with multiple facilities requiring decommissioning, $500 million to $1 billion depending on the number of such facilities. Another large materials licensee suggests that NRC use the same financial requirements now applicable to parent company

guarantees. It does not see any need to make the tangible net worth criterion any higher than $50 million. The minimum bond rating requirement should be BBB or Baa, the lowest rating still considered investment grade. Also, in their opinion, the financial ratio tests in appendix A to 10 CFR part 30 should be retained as an alternative to the bond rating criterion. Finally, this commenter does not believe that the more restrictive tangible net worth/decommissioning cost ratio proposed in the petition is justified. Another large materials licensee asserts that there is no rational basis for establishing criteria for a company self-guarantee which differ significantly from existing criteria for the parent company guarantee. In either instance, the adequacy of the financial assurance requirement provided is based on the value of the assets securing the decommissioning obligation. According to this commenter, if the assets are held in two separate pools, each technically owned by a different but related company, the level of financial security provided does not increase in any significant measure. In virtually all instances where the parent guarantee is utilized, the subsidiaries are wholly or substantially owned by the parent such that the financial and other elements of the two entities are substantially the same. As an alternative, this commenter recommends that the NRC adopt the petitioners' proposal, modified by reducing the minimum tangible net worth requirement to at most $100 million, and requiring a bond rating not lower than BBB or Baa.

An electric utility licensee opposes the petition's exclusion of the electric utility reactor licensees under 10 CFR part 50. Its position is that decommissioning regulations should apply to all licensees equally and that compliance alternatives contingent on licensee financial status and size should also be available to utilities.

A commenter opposed self-guarantee, citing the potential for takeover and breakup of large corporations. This would mean that a company initially allowed to use a self guarantee by meeting the criteria, subsequently could be substantially weakened through restructuring. The ability of the restructured company to meet decommissioning costs could be in doubt.

Response to Comments

Several commenters favored the self guarantee concept but argued for less stringent financial criteria. The Commission is interested in alternative financial criteria which would permit more licensees to use the proposed self-guarantee, yet would maintain a high level of financial assurance. The Commission is asking for public comments on a possible alternative to the proposed financial criteria (see Alternative Criteria).

Regarding the comment concerning the exclusion of electric utilities from the scope of the proposed self-guarantee, the Commission allows electric utilities to accumulate decommissioning funds in an external sinking fund. Unlike other licensees subject to financial assurance requirements, electric utilities do not have to provide financial assurance "up front." Thus, electric utilities already are permitted a cost-reducing financial assurance mechanism.

In response to the comment that self-guarantee should not be allowed because of the potential for takeover and breakup of large companies, the Commission believes that the requirements for annual re-certification, combined with timely bond rating reviews, will be adequate to maintain the level of financial assurance of the proposed self-guarantee.

Basis for the Commission's Decision

The Commission has carefully reviewed the arguments in the petition, as well as the public comments. For the reasons outlined below, it has decided to initiate this rulemaking, which, if promulgated as final, would grant the petition.

Stringent Financial Criteria

The financial criteria proposed for self-guarantee are exceptionally stringent. The Commission is confident that licensees able to meet the financial criteria provide the necessary reasonable assurance that funding will be available to meet decommissioning costs. The regulatory analysis estimates that only approximately 20 present NRC licensees could meet the criteria.

The criterion for tangible net worth, $1 billion, far exceeds that required for the NRC parent company guarantee ($10 million). In addition to the $1 billion tangible net worth requirement, the proposed rule would require that a licensee must have tangible net worth at least ten times the total current decommissioning cost estimate for all decommissioning activities for which the company is responsible as self-guaranteeing licensee and as parent-guarantor, or the current amount required if certification is used. To assure that assets are within reach of the Commission's authority, 90 percent of total assets or at least ten times total decommissioning cost estimates for all decommissioning activities for which the company is responsible as self-guaranteeing licensee and as parent-guarantor, or the current amount if certification is used, would need to be in the United States.

In addition to tangible net worth criteria, the financial criteria include a bond rating of A or above. This bond rating is above that required to classify debt securities as "investment grade." The principal debt rating services, Moodys and Standard and Poors, classify bonds with a rating of Baa and BBB respectively, as "investment grade as opposed to bonds with a lesser rating which are classified as "speculative grade." Bond ratings are reviewed often, and changed in response to changes in the issuer's financial condition. A bond rating of A or better assures that the financial strength of a licensee offering a self-guarantee has been independently reviewed and affirmed. It provides an excellent guide to the ability of a company to meet its obligations. According to Moodys, default rates associated with companies whose bonds are rated A or above in 1 of 3 years prior to default are 0.13 percent annually.[1]

There could be concern that a self-guaranteeing licensee's financial condition could deteriorate over time, jeopardizing decommissioning funding. The proposed rule has the following safeguards against this possibility: (1) A licensee using self-guarantee would need to be re-certified each year as meeting the financial criteria, (2) Copies of all current financial reports filed with the Securities and Exchange Commission would also need to be provided to the Commission, (3) The company would need to notify NRC within 90 days of any matters which could prevent the company from any longer passing the financial criteria, and (4) The company would need to notify NRC within 20 days if its bonds are no longer rated A or better.

Cost Savings

The objective of this proposed rule is to reduce the licensee's cost burden without adverse effects on public health and safety. The draft regulatory analysis developed for this proposed rule estimates that annual total cost savings would be approximately $600,000 for all licensees using the self-guarantee. This estimate is based on rather conservative assumptions (i.e., $750,000 total decommissioning cost per license); the actual cost savings may be considerably greater. Both the petition for rulemaking

[1] Corporate Bond Defaults and Default Rates, Moody's Special Report, January 1991, p. 32.

and several public comment letters assert much greater cost savings.

The cost savings would result from the elimination of the cost of third party financial assurance for licensees qualifying to use the proposed self-guarantee. Annual fees for letters of credit, surety bonds, and other forms of third party financial assurance typically are approximately 1.5 percent of the amount of financial assurance provided.

Comparison With Parent Guarantee

The NRC currently allows licensees to comply with his financial assurance regulations by means of a parent company guarantee. The parent company of a licensee, if it meets the financial criteria in 10 CFR part 30, appendix A, may guarantee that funds will be available to decommission the facility of its subsidiary licensee. The parent company guarantee allowed in NRC regulations does not provide a greater degree of financial assurance than self-guarantee for a company meeting the criteria proposed here. Under current regulations, there is no explicit regulatory requirement that licensees using the parent company guarantee: (1) Be wholly independent of the parent company who provides the guarantee and (2) demonstrate financial qualifications in itself that are comparable to those required of a parent company guarantor under current regulations or those proposed for self-guarantee in the petition.

A company which meets the financial criteria for the proposed rule could readily pass the financial test in 10 CFR part 30, appendix A, and would thus be eligible to provide a parent company guarantee for a subsidiary. It is anomalous for NRC regulations to permit a large, financially strong company to provide a parent company guarantee, but not allow that same company to provide a self-guarantee. Moreover, a large, financially strong company could carry out a corporate restructuring to create a licensee subsidiary which could then be covered by a parent company guarantee.

EPA Precedent

The Environmental Protection Agency (EPA) allows self-guarantee as a mechanism for meeting its financial assurance regulations for hazardous waste facilities (40 CFR parts 264 and 265). The objective of EPA and NRC financial assurance regulations is the same; to ensure that adequate funds are available to safely decommission facilities. EPA has about 10 years of experience with self-guarantee to date (the final rule was promulgated on April 7, 1982, 47 FR 15033), and self-guarantee has been an effective financial assurance mechanism.

Alternative Criteria

The Commission notes that a majority of commenters on the petition questioned the need for the financial criteria for self-guarantee to be as stringent as proposed here. Allowing less stringent criteria would permit additional licensees to use self-guarantee and thus reduce the costs of complying with the Commission's regulations. The draft regulatory analysis indicates that one approach which could widen the range of eligible licensees would be to delete the $1 billion tangible net worth criterion. A company's tangible net worth is an important factor comprising its bond rating, and the rating itself, combined with the other criteria, may be a sufficient indicator of financial stability. Since all firms qualifying would need an A or better bond rating, this alternative may not be riskier in terms of financial assurance than the proposed rule. The draft regulatory analysis examines the effects of deleting the $1 billion tangible net worth requirement from the financial criteria in the proposed rule, all other criteria remaining constant. The conclusion is that this alternative, if adopted, would allow an additional 7 firms, holding 11 licenses, to use the proposed self-guarantee. The Commission is especially interested in public comments on this alternative financial criteria—the criteria in this proposed rule without the $1 billion tangible net worth requirement.

Administrative Conforming Changes

Sections 30.8(b), 40.8(b) and 50.8(b) are being revised to list all the regulatory provisions of these parts that contain information collections.

Environmental Impact: Categorical Exclusion

The NRC has determined that this proposed regulation is the type of action described as a categorical exclusion in 10 CFR 51.22(c)(10)(i). Therefore, neither an environmental impact statement nor an environmental assessment has been prepared for this proposed regulation.

Paperwork Reduction Act Statement

This proposed rule amends information collection requirements that are subject to the Paperwork Reduction Act of 1980 (44 U.S.C. 3501, *et seq.*). This rule has been submitted to the Office of Management and Budget for review and approval of the paperwork requirements.

The public reporting burden for this collection of information is estimated to average 19 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the Information and Records Management Branch (MNBB–7714), U.S. Nuclear Regulatory Commission, Washington, DC 20555, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB–3019, (3150–0017, –0020, –0011, –0009, –0132), Office of Management and Budget, Washington, DC 20503.

Regulatory Analysis

The Commission has prepared a draft regulatory analysis on this proposed regulation. The analysis examines the costs and benefits of the alternatives considered by the Commission. The draft analysis is available for inspection in the NRC Public Document Room, 2120 L Street, NW. (Lower Level), Washington, DC. Single copies of the draft analysis may be obtained from Clark W. Prichard, Office of Nuclear Regulatory Research, U.S. Nuclear Regulatory Commission, Washington, DC, 20555 telephone (301) 492–3734.

The Commission requests public comment on the draft regulatory analysis. Comments on the draft analysis may be submitted to the NRC as indicated under the **ADDRESSES** hearing.

Regulatory Flexibility Certification

In accordance with the Regulatory Flexibility Act, 5 U.S.C. 605(b), the Commission certifies that, if promulgated, this proposed rule will not have a significant economic impact upon a substantial number of small entities. The proposed rule would affect only entities with a tangible net worth of $1 billion. The licensees affected by this proposed rule do not fall within the scope of the definition of "small entities" set forth in the Regulatory Flexibility Act or the size standards of the NRC applicable to a small business (56 FR 56671; November 6, 1991).

Backfit Analysis

The NRC has determined that the backfit rule, 10 CFR 50.109, does not apply to this proposed rule and, therefore, that a backfit analysis is not required for this proposed rule, because these amendments do not involve any

provisions which would impose backfits as defined in 10 CFR 50.109(a)(1).

List of Subjects

10 CFR Part 30

Byproduct material, Civil penalty, Government contracts, Intergovernmental relations, Isotopes, Nuclear material, Radiation protection, Reporting and recordkeeping requirements.

10 CFR Part 40

Criminal penalty, Government contracts, Hazardous materials-transport, Nuclear materials, Reporting and recordkeeping requirements, Source material, Uranium.

10 CFR Part 50

Antitrust, Classified information, Criminal penalty, Fire protection, Incorporation by reference, Intergovernmental relations, Nuclear power plants and reactors, Radiation protection, Reactor siting criteria, Reporting and recordkeeping requirements.

10 CFR Part 70

Criminal penalty, Hazardous materials-transportation, Material control and accounting, Nuclear materials, Packaging and containers, Penalty, Radiation protection, Reporting and recordkeeping requirements, Scientific equipment, Security measures, Special nuclear material.

10 CFR Part 72

Manpower training programs, Nuclear materials, Occupational safety and health, Reporting and recordkeeping requirements, Security measures, Spent fuel.

For the reasons set out in the preamble and under the authority of the Atomic Energy Act of 1954, as amended, the Energy Reorganization Act of 1974, as amended, and 5 U.S.C. 553, the NRC is proposing to adopt the following amendments to 10 CFR parts 30, 40, 50, 70, and 72.

PART 30—RULES OF GENERAL APPLICABILITY TO DOMESTIC LICENSING OF BYPRODUCT MATERIAL

1. The authority citation for part 30 continues to read as follows:

Authority: Secs. 81, 82, 161, 182, 183, 186, 68 Stat. 935, 948, 953, 954, 955, as amended, sec. 234, 83 Stat. 444, as amended (42 U.S.C. 2111, 2112, 2201, 2232, 2233, 2236, 2282); secs. 201, as amended, 202, 206, 88 Stat. 1242, as amended, 1244, 1246 (42 U.S.C. 5841, 5842, 5846).

Section 30.7 also issued under Pub. L. 95–601, sec. 10, 92 Stat. 2951 (42 U.S.C. 5851). Section 30.34(b) also issued under sec. 184, 68 Stat. 954, as amended (42 U.S.C. 2234). Section 30.61 also issued under sec. 187, 68 Stat. 955 (42 U.S.C. 2237).

For the purposes of sec. 223, 68 Stat. 958, as amended (42 U.S.C. 2273); §§ 30.3, 30.10, 30.34 (b), (c), (f), (g) and (i), 30.41 (a) and (c), and 30.53 are issued under sec. 161b, 68 Stat. 948, as amended (42 U.S.C. 2201(b)); § 30.10 is issued under sec. 161i, 68 Stat. 949, as amended (42 U.S.C. 2201(i)); and §§ 30.6, 30.9, 30.34(g), 30.36, 30.50, 30.51, 30.52, 30.55, and 30.56 (b) and (c) are issued under sec. 161o, 68 Stat. 950, as amended (42 U.S.C. 2201(o)).

2. In § 30.8 paragraph (b) is revised to read as follows:

§ 30.8 Information collection requirements: OMB approval.

* * * * *

(b) The approved information collection requirements contained in this part appear in §§ 30.15, 30.19, 30.20, 30.32, 30.34, 30.35, 30.36, 30.37, 30.38, 30.50, 30.51, 30.55, 30.56, and appendix A and B.

* * * * *

3. In § 30.35, the introductory text of paragraph (f)(2) is revised to read as follows:

§ 30.35 Financial assurance and recordkeeping for decommissioning.

* * * * *

(f) * * *

(1) * * *

(2) A surety method, insurance, or other guarantee method. These methods guarantee that decommissioning costs will be paid. A surety method may be in the form of a surety bond, letter of credit, or line of credit. A parent company guarantee of funds for decommissioning costs based on a financial test may be used if the guarantee and test are as contained in appendix A of this part. A parent company guarantee may not be used in combination with other financial methods to satisfy the requirements of this section. A guarantee of funds by the applicant or licensee for decommissioning costs based on a financial test may be used if the guarantee and test are as contained in appendix B of this part. A guarantee by the applicant or licensee may not be used in combination with any other financial methods to satisfy the requirements of this section or in any situation where the applicant or licensee has a parent company holding majority control of the voting stock of the company. Any surety method or insurance used to provide financial assurance for decommissioning must contain the following conditions:

* * * * *

4. A new appendix B is added to part 30 to read as follows:

Appendix B to Part 30—Criteria Relating to Use of Financial Tests and Self Guarantees for Providing Reasonable Assurance of Funds for Decommissioning

I. Introduction

An applicant or licensee may provide reasonable assurance of the availability of funds for decommissioning based on furnishing its own guarantee that funds will be available for decommissioning costs and on a demonstration that the company passes the financial test of section II of this appendix. The terms of the self-guarantee are in section III of this appendix. This appendix establishes criteria for passing the financial test for the self guarantee and establishes the terms for a self-guarantee.

II. Financial Test

A. To pass the financial test, a company must meet all of the following criteria:

(1) Tangible net worth of at least $1 billion.

(2) Tangible net worth at least 10 times the total current decommissioning cost estimate for all decommissioning activities for which the company is responsible as self-guaranteeing licensee and as parent-guarantor, or the current amount required if certification is used.

(3) Assets located in the United States amounting to at least 90 percent of total assets or at least 10 times the total current decommissioning cost estimate for all decommissioning activities for which the company is responsible as self-guaranteeing licensee and as parent-guarantor, or the current amount required if certification is used.

(4) A current rating for its most recent bond issuance of AAA, AA, or A as issued by Standard and Poors (S&P), or Aaa, Aa, or A as issued by Moodys.

B. To pass the financial test, a company must meet all of the following additional requirements:

(1) The company must have at least one class of equity securities registered under the Securities Exchange Act of 1934.

(2) The company's independent certified public accountant must have compared the data used by the company in the financial test which is derived from the independently audited, yearend financial statements for the latest fiscal year, with the amounts in such financial statement. In connection with that procedure, the licensee shall inform NRC within 90 days of any matters coming to the attention of the

auditor that cause the auditor to believe that the data specified in the financial test should be adjusted and that the company no longer passes the test.

(3) After the initial financial test, the company must repeat passage of the test within 90 days after the close of each succeeding fiscal year.

III. Company Self-Guarantee

The terms of a self-guarantee which an applicant or licensee furnishes must provide that:

A. The guarantee will remain in force unless the licensee sends notice of cancellation by certified mail to the Commission. Cancellation may not occur, however, during the 120 days beginning on the date of receipt of the notice of cancellation by the Commission, as evidenced by the return receipt.

B. The licensee will provide alternative financial assurance as specified in the Commission's regulations within 90 days following receipt by the Commission of a notice of cancellation of the guarantee.

C. The guarantee and financial test provisions must remain in effect until the Commission has terminated the license or until another financial assurance method acceptable to the Commission has been put in effect by the licensee.

D. The licensee will promptly forward to the Commission and the licensee's independent auditor all reports covering the latest fiscal year filed by the licensee with the Securities and Exchange Commission pursuant to the requirements of section 13 of the Securities and Exchange Act of 1934.

E. If, at any time, the licensee's most recent bond issuance ceases to be rated in any category of "A" or above by either Standard and Poors or Moodys, the licensee will provide notice in writing of such fact to the Commission within 20 days after publication of the change by the rating service.

PART 40—DOMESTIC LICENSING OF SOURCE MATERIAL

5. The authority citation for part 40 continues to read as follows:

Authority: Secs. 62, 63, 64, 65, 81, 161, 182, 183, 186, 68 Stat. 932, 933, 935, 948, 953, 954, 955, as amended, secs. 11e(2), 83, 84, Pub. L. 95–604, 92 Stat. 3033, as amended, 3039, sec. 234, 83 Stat. 444, as amended (42 U.S.C. 2014(e)(2), 2092, 2093, 2094, 2095, 2111, 2113, 2114, 2201, 2232, 2233, 2236, 2282); sec. 274, Pub. L. 86–373, 73 Stat. 688 (42 U.S.C. 2021); secs. 201, as amended, 202, 206, 88 Stat. 1242, as amended, 1244, 1246 (42 U.S.C. 5841, 5842, 5846); sec. 275, 92 Stat. 3021, as amended by Pub. L. 97–415, 96 Stat. 2067 (42 U.S.C. 2022).

Section 40.7 also issued under Pub. L. 95–601, sec. 10, 92 Stat. 2951 (42 U.S.C. 5851). Section 40.31(g) also issued under sec. 122, 68 Stat. 939 (42 U.S.C. 2152). Section 40.46 also issued under sec. 184, 68 Stat. 954, as amended (42 U.S.C. 2234). Section 40.71 also issued under sec. 187, 68 Stat. 955 (42 U.S.C. 2237).

For the purposes of sec. 223, 68 Stat. 958, as amended (42 U.S.C. 2273); §§ 40.3, 40.25(d) (1)–(3), 40.35 (a)–(d) and (f), 40.41 (b) and (c), 40.46, 40.51 (a) and (c), and 40.63 are issued under sec. 161b, 68 Stat. 948, as amended (42 U.S.C. 2201(b)); § 40.10 is issued under sec. 161i, 68 Stat. 949, as amended (42 U.S.C. 2201(i)); and §§ 40.5, 40.9, 40.25 (c), (d) (3) and (4), 40.26(c)(2), 40.35(e), 40.42, 40.60 40.61, 40.62, 40.64, and 40.65 are issued under sec. 161o, 68 Stat. 950, as amended (42 U.S.C. 2201(o)).

6. In § 40.8 paragraph (b) is revised to read as follows:

§ 40.8 Information collection requirements: OMB approval.

* * * * *

(b) The approved information collection requirements contained in this part appear in §§ 40.25, 40.26, 40.31, 40.35, 40.36, 40.42, 40.43, 40.44, 40.60, 40.61, 40.64, 40.65, and appendix A.

7. In § 40.36 the introductory text of paragraph (e)(2) is revised to read as follows:

§ 40.36 Financial assurance and recordkeeping for decommissioning.

* * * * *

(e) * * *

(2) A surety method, insurance, or other guarantee method. These methods guarantee that decommissioning costs will be paid. A surety method may be in the form of a surety bond, letter of credit, or line of credit. A parent company guarantee of funds for decommissioning costs based on a financial test may be used if the guarantee and test are as contained in appendix A of 10 CFR part 30. A parent company guarantee may not be used in combination with other financial methods to satisfy the requirements of this section. A guarantee of funds by the applicant or licensee for decommissioning costs based on a financial test may be used if the guarantee and test are as contained in appendix B of 10 CFR part 30. A guarantee by the applicant or licensee may not be used in combination with any other financial methods to satisfy the requirements of this section or in any situation where the applicant or licensee has a parent company holding majority control of the voting stock of the company. Any surety method or insurance used to provide financial assurance for decommissioning must contain the following conditions:

* * * * *

PART 50—DOMESTIC LICENSING OF PROTECTION AND UTILIZATION FACILITIES

8. The authority citation for part 50 continues to read as follows:

Authority: Secs. 102, 103, 104, 105, 161, 182, 183, 186, 189, 68 Stat. 936, 937, 938, 948, 953, 954, 955, 956, as amended, sec. 234, 83 Stat. 1244, as amended (42 U.S.C. 2132, 2133, 2134, 2135, 2201, 2232, 2233, 2236, 2239, 2282); secs. 201, as amended, 202, 206, 88, Stat. 1242, as amended, 1244, 1246 (42 U.S.C. 5841, 5842, 5846).

Section 50.7 also issued under Pub. L. 95–601, sec. 10, 92 Stat. 2951 (42 U.S.C. 5851). Section 50.10 also issued under secs. 101, 185, 68 Stat. 936, 955, as amended (42 U.S.C. 2131, 2235); sec. 102, Pub. L. 91–190, 83 Stat. 853 (42 U.S.C. 4332). Sections 50.13, 50.54(dd), and 50.103 also issued under sec. 108, 68 Stat. 939, as amended (42 U.S.C. 2138). Sections 50.23, 50.35, 50.55, and 50.56 also issued under sec. 185, 68 Stat. 955 (42 U.S.C. 2235). Sections 50.33a, 50.55a and Appendix Q also issued under sec. 102, Pub. L. 91–190, 83 Stat. 853 (42 U.S.C. 4332). Sections 50.34 and 50.54 also issued under sec. 204, 88 Stat. 1245 (42 U.S.C. 5844). Sections 50.58, 50.91, and 50.92 also issued under Pub. L. 97–415, 96 Stat. 2073 (42 U.S.C. 2239). Section 50.78 also issued under sec. 122, 68 Stat. 939 (42 U.S.C. 2152). Sections 50.80–50.81 also issued under sec. 184, 68 stat. 954, as amended (42 U.S.C. 2234). Appendix F also issued under sec. 187, 68 Stat. 955 (42 U.S.C. 2237).

For the purposes of sec. 223, 68 Stat. 958, as amended (42 U.S.C. 2273); § § 50.5, 50.46 (a) and (b), and 50.54(c) are issued under sec. 161b, 68 Stat. 948, as amended (42 U.S.C. 2201(b)); § § 50.5, 50.7(a), 50.10 (a)–(c), 50.34 (a) and (e), 50.44 (a)–(c), 50.46 (a) and (b), 50.47(b), 50.48 (a), (c), (d), and (e), 50.49(a), 50.54 (a), (i), (i)(1), (l)–(n), (p), (q), (t), (v), and (y), 50.55(f), 50.55a (a), (c)–(e), (g), and (h), 50.59(c), 50.60(a), 50.62(b), 50.64(b), 50.65, and 50.80 (a) and (b) are issued under sec. 161i, 68 Stat. 949, as amended (42 U.S.C. 2201(i)); and § § 50.9, 50.49 (d), (h), and (j), 50.54 (w), (z), (bb), (cc), and (dd), 50.55(e), 50.59(b), 50.61(b), 50.62(b), 50.70(a), 50.71(a)–(c) and (e), 50.72(a), 50.73 (a) and (b), 50.74, 50.78, and 50.90 are issued under sec. 161o, 68 Stat. 950, as amended (42 U.S.C. 2201(o)).

9. In § 50.8 paragraph (b) is revised to read as follows:

§ 50.8 Information collection requirements: OMB approval.

* * * * *

(b) The approved information collection requirements contained in this part appear in § § 50.30, 50.33, 50.33a, 50.34, 50.34a, 50.35, 50.36, 50.36a, 50.48, 50.49, 50.54, 50.55, 50.55a, 50.59, 50.60, 50.61, 50.63, 50.64, 50.65, 50.71, 50.72, 50.75, 50.80, 50.82,

50.90, 50.91, and appendices A, B, E, G, H, I, J, K, M, N, O, Q, and R.

10. In § 50.75 the introductory text of paragraph (e)(1)(iii) and paragraph (e)(2)(iii) are revised to read as follows:

§ 50.75 Reporting and recordkeeping for decommissioning planning.

* * * * *

(e) * * *

(1) * * *

(iii) A surety method, insurance, or other guarantee method. These methods guarantee that decommissioning costs will be paid. A surety method may be in the form of a surety bond, letter of credit, or line of credit. Any surety method or insurance used to provide financial assurance for decommissioning must contain the following conditions:

* * * * *

(2) * * *

(iii) A surety method, insurance, or other guarantee method. A parent company guarantee of funds for decommissioning costs based on a financial test may be used if the guarantee and test are as contained in appendix A of 10 CFR part 30. A parent company guarantee may not be used in combination with other financial methods to satisfy the requirements of this section. A guarantee of funds by the applicant or licensee for decommissioning costs based on a financial test may be used if the guarantee and test are as contained in appendix B of 10 CFR part 30. A guarantee by the applicant or the licensee may not be used in combination with any other financial methods to satisfy the requirements of this section or in any situation where the applicant or licensee has a parent company holding majority control of the voting stock of the company.

* * * * *

PART 70—DOMESTIC LICENSING OF SPECIAL NUCLEAR MATERIAL

11. The authority citation for part 70 continues to read as follows:

Authority: Secs. 51, 53, 161, 182, 183, 68 Stat. 929, 930, 948, 953, 954, as amended, sec. 234, 83 Stat. 444, as amended (42 U.S.C. 2071, 2073, 2201, 2232, 2233, 2282); secs. 201, as amended, 202, 204, 206, 88 Stat. 1242, as amended, 1244, 1245, 1246 (42 U.S.C. 5841, 5842, 5845, 5846).

Sections 70.1(c) and 70.20a(b) also issued under secs. 135, 141, Pub. L. 97–425, 96 Stat. 2232, 2241 (42 U.S.C. 10155, 10161). Section 70.7 also issued under Pub. L. 95–601, sec. 10, 92 Stat. 2951 (42 U.S.C. 5851). Section 70.21(g) also issued under sec. 122, 68 Stat. 939 (42 U.S.C. 2152). Section 70.31 also issued under sec. 57d, Pub. L. 93–377, 88 Stat. 475 (42 U.S.C. 2077). Sections 70.36 and 70.44 also issued under sec. 184, 68 Stat. 954, as amended (42 U.S.C. 2234). Section 70.61 also issued under secs. 186, 187, 68 Stat. 955 (42 U.S.C. 2236, 2237). Section 70.62 also issued under sec. 108, 68 Stat. 939, as amended (42 U.S.C. 2138).

For the purposes of sec. 223, 68 Stat. 958, as amended (42 U.S.C. 2273); §§ 70.3, 70.10, 70.19(c), 70.21(c), 70.22 (a), (b), (d)–(k), 70.24 (a) and (b), 70.32 (a) (3), (5), (6), (d), and (i), 70.36, 70.39 (b) and (c), 70.41(a), 70.42 (a) and (c), 70.56, 70.57 (b), (c), and (d), 70.58 (a)–(g)(3) and (h)–(j) are issued under sec. 161b, 68 Stat. 948, as amended (42 U.S.C. 2201(b)); §§ 70.7, 70.10, 70.20a (a) and (d), 70.20b (c) and (e), 70.21(c), 70.24(b), 70.32 (a), (b), (c), (d), (e), and (g), 70.36, 70.51 (c)–(g), 70.56, 70.57 (b) and (d), and 70.58 (a)–(g)(3) and (h)–(j) are issued under sec. 161i, 68 Stat. 949, as amended (42 U.S.C. 2201(i)); and §§ 70.5, 70.9, 70.20b (d) and (e), 70.38, 70.50, 70.51 (b) and (i), 70.52, 70.53, 70.54, 70.55, 70.58 (g)(4), (k), and (l), 70.59 and 70.60 (b) and (c) are issued under sec. 161o, 68 Stat. 950, as amended (42 U.S.C. 2201(o)).

12. In § 70.25, the introductory text of paragraph (f)(2) is revised to read as follows:

§ 70.25 Financial assurance and recordkeeping for decommissioning.

* * * * *

(f) * * *

(2) A surety method, insurance, or other guarantee method. These methods guarantee that decommissioning costs will be paid. A surety method may be in the form of a surety bond, letter of credit, or line of credit. A parent company guarantee of funds for decommissioning costs based on a financial test may be used if the guarantee and test are as contained in appendix A of 10 CFR part 30. A parent company guarantee may not be used in combination with other financial methods to satisfy the requirements of this section. A guarantee of funds by the applicant or licensee for decommissioning costs based on a financial test may be used if the guarantee and test are as contained in appendix B of 10 CFR part 30. A guarantee by the applicant or the licensee may not be used in combination with any other financial methods to satisfy the requirements of this section or in any situation where the applicant or licensee has a parent company holding majority control of the voting stock of the company. Any surety method or insurance used to provide financial assurance for decommissioning must contain the following conditions:

* * * * *

PART 72—LICENSING REQUIREMENTS FOR THE INDEPENDENT STORAGE OF SPENT NUCLEAR FUEL AND HIGH-LEVEL RADIOACTIVE WASTE

13. The authority citation for part 72 continues to read as follows:

Authority: Secs. 51, 53, 57, 62, 63, 65, 69, 81, 161, 182, 183, 184, 186, 187, 189, 68 Stat. 929, 930, 932, 933, 934, 935, 948, 953, 954, 955, as amended, sec. 234, 83 Stat. 444, as amended (42 U.S.C. 2071, 2073, 2077, 2092, 2093, 2095, 2099, 2111, 2201, 2232, 2233, 2234, 2236, 2237, 2238, 2282); sec. 274, Pub. L. 86–373, 73 Stat. 688, as amended (42 U.S.C. 2021); sec. 201, as amended, 202, 206, 88 Stat. 1242, as amended, 1244, 1246 (42 U.S.C. 5841, 5842, 5846); Pub. L. 95–601, sec. 10, 92 Stat. 2951 (42 U.S.C. 5851); sec. 102, Pub. L. 91–190, 83 Stat. 853 (42 U.S.C. 4332); Secs. 131, 132, 133, 135, 137, 141, Pub. L. 97–425, 96 Stat. 2229, 2230, 2232, 2241, sec. 148, Pub. L. 100–203, 101 Stat. 1330–235 (42 U.S.C. 10151, 10152, 10153, 10155, 10157, 10161, 10168).

Section 72.44(g) also issued under secs. 142(b) and 148 (c), (d), Pub. L. 100–203, 101 Stat. 1330–232, 1330–236 (42 U.S.C. 10162(b), 10168 (c), (d)). Section 72.46 also issued under sec. 189, 68 Stat. 955 (42 U.S.C. 2239); sec. 134, Pub. L. 97–425, 96 Stat. 2230 (42 U.S.C. 10154). Section 72.96(d) also issued under sec. 145(g), Pub. L. 100–203, 101 Stat. 1330–235 (42 U.S.C. 10165(g)). Subpart J also issued under secs. 2(2), 2(15), 2(19), 117(a), 141(h), Pub. L. 97–425, 96 Stat. 2202, 2203, 2204, 2222, 2244 (42 U.S.C. 10101, 10137(a), 10161(h)). Subparts K and L are also issued under sec. 133, 98 Stat. 2230 (42 U.S.C. 10153) and sec. 218(a), 96 Stat. 2252 (42 U.S.C. 10198).

For the purposes of sec. 223, 68 Stat. 958, as amended (42 U.S.C. 2273); §§ 72.6, 72.12, 72.22, 72.24, 72.26, 72.28(d), 72.30, 72.32, 72.44 (a), (b) (1), (4), (5), (c), (d) (1), (2), (e), (f), 72.48(a), 72.50(a), 72.52(b), 72.72 (b), (c), 72.74 (a), (b), 72.76, 72.78, 72.104, 72.106, 72.120, 72.122, 72.124, 72.126, 72.128, 72.130, 72.140 (b), (c), 72.148, 72.154, 72.156, 72.160, 72.166, 72.168, 72.170, 72.172, 72.176, 72.180, 72.184, 72.186 are issued under sec. 161b, 68 Stat. 948, as amended (42 U.S.C. 2201(b)); §§ 72.10 (a), (e), 72.12, 72.22, 72.24, 72.26, 72.28, 72.30, 72.32, 72.44 (a), (b), (1), (4), (5), (c), (d) (1), (2), (e), (f), 72.48 (a), 72.50(a), 72.52(b), 72.90 (a)–(d), (f), 72.92, 72.94, 72.98, 72.100, 72.102 (c), (d), (f), 72.104, 72.106, 72.120, 72.122, 72.124, 72.126, 72.128, 72.130, 72.140 (b), (c), 72.142, 72.144, 72.146, 72.148, 72.150, 72.152, 72.154, 72.156, 72.158, 72.160, 72.162, 72.164, 72.166, 72.168, 72.170, 72.172, 72.176, 72.180, 72.182, 72.184, 72.186, 72.190, 72.192, 72.194 are issued under sec. 161i, 68 Stat. 949, as amended (42 U.S.C. 2201(i)); and §§ 72.10(e), 72.11, 72.16, 72.22, 72.24, 72.26, 72.28, 72.30, 72.32, 72.44 (b)(3), (c)(5), (d)(3), (e), (f), 72.48 (b), (c), 72.50(b), 72.54 (a), (b), (c), 72.56, 72.70, 72.72, 72.74 (a), (b), 72.76(a), 72.78(a), 72.80, 72.82, 72.92(b), 72.94(b), 72.140 (b), (c), (d), 72.144(a), 72.146, 72.148, 72.150, 72.152, 72.154 (a), (b), 72.156, 72.160, 72.162, 72.168, 72.170, 72.172, 72.174, 72.176, 72.180,

72.184, 72.186, 72.192, 72.212(b), 72.216, 72.218, 72.230, 72.234 (e) and (g) are issued under sec. 161o, 68 Stat. 950, as amended (42 U.S.C. 2201(o)).

14. In § 72.30 the introductory text of paragraph (c)(2) is revised to read as follows:

§ 72.30 Decommissioning Planning including financing and recordkeeping.

* * * * *

(c) * * *

(2) A surety method, insurance, or other guarantee method. These methods guarantee that decommissioning costs will be paid. A surety method may be in the form of a surety bond, letter of credit, or line of credit. A parent company guarantee of funds for decommissioning costs based on a financial test may be used if the guarantee and test are as contained in appendix A of 10 CFR part 30. A parent company guarantee may not be used in combination with other financial methods to satisfy the requirements of this section. A guarantee of funds by the applicant or licensee for decommissioning costs based on a financial test may be used if the guarantee and test are as contained in appendix B of 10 CFR part 30. A guarantee by the applicant or the licensee may not be used in combination with any other financial methods to satisfy the requirements of this section or in any situation where the applicant or licensee has a parent company holding majority control of the voting stock for the company. Any surety method or insurance used to provide financial assurance for decommissioning must contain the following conditions:

* * * * *

Dated at Rockville, Maryland, this 5th day of January, 1993.

For the Nuclear Regulatory Commission.

Samuel J. Chilk,

Secretary of the Commission.

[FR Doc. 93–473 Filed 1–8–93; 8:45 am]

BILLING CODE 7590–01–M

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 1

[CO–76–90]

RIN 1545–AP19

Regulations Under Section 108 of the Internal Revenue Code; Discharge of Indebtedness; Hearing Cancellation

AGENCY: Internal Revenue Service, Treasury.

ACTION: Cancellation of notice of public hearing on proposed regulations.

SUMMARY: This document provides notice of cancellation of a public hearing on proposed regulations that provide rules for determining whether stock issued for indebtedness is nominal or token under section 108(e)(8)(A) and rules for applying the proportionality test of section 108(e)(8)(B).

DATES: The public hearing originally scheduled for Tuesday, January 12, 1993, beginning at 10 a.m. is cancelled.

FOR FURTHER INFORMATION CONTACT: Mike Slaughter of the Regulations Unit, Assistant Chief Counsel (Corporate), 202–622–7190, (not a toll-free number).

SUPPLEMENTARY INFORMATION: The subject of the public hearing is proposed regulations under section 108(e)(8) of the Internal Revenue Code of 1986. A notice of public hearing appearing in the **Federal Register** for Monday, November 30, 1992 (57 FR 56534), announced that the public hearing on proposed regulations under section 108(e)(8) of the Internal Revenue Code of 1986 would be held on Tuesday, January 12, 1993, beginning at 1 p.m., in the IRS Commissioner's Conference Room, room 3313, Internal Revenue Building, 1111 Constitution Avenue, NW., Washington, DC.

The public hearing scheduled for Tuesday, January 12, 1993, has been cancelled.

Cynthia E. Grigsby,

Alternate Federal Register Liaison Officer, Assistant Chief Counsel (Corporate).

[FR Doc. 93–646 Filed 1–7–93; 2:33 am]

BILLING CODE 4830–01–M

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Chapter I

[CC Docket No. 90–337, Phase II; FCC 92–496]

International Accounting Rates: In the Matter of Regulation of

AGENCY: Federal Communications Commission.

ACTION: Proposed rule.

SUMMARY: On November 5, 1992, the Commission adopted a Second Further Notice of Proposed Rulemaking in Phase II of the Regulation of International Accounting Rates proceeding seeking comment on whether conditioning section 214 authorizations or modifying its nondiscriminatory accounting rate, equal division of tolls or proportionate return requirements might be an appropriate means of achieving lower accounting rates as facilities-based competition is introduced in foreign countries.

DATES: Comments on the Second Further Notice of Proposed Rulemaking are due February 5, 1993; Reply Comments are due March 8, 1993.

ADDRESSES: Federal Communications Commission, 1919 M Street, NW., Washington, DC 20554.

FOR FURTHER INFORMATION CONTACT: Teresa Marrero, Attorney, Common Carrier Bureau, (202) 632–3214.

SUPPLEMENTARY INFORMATION: This is a summary of the Commission's Second Further Notice of Proposed Rulemaking adopted November 5, 1992, and released November 27, 1992. The full text of this Commission decision is available for inspection and copying during normal business hours in the Federal Communications Commission Reference Center, Room 239, 1919 M Street, NW., Washington, DC. The complete text of this decision also may be purchased from the Commission's copy contractor, Downtown Copy Center, (202) 452–1422, 1114 21st Street, NW., Washington, DC 20036.

Paperwork Reduction Act

The proposals will not create any undue burden on the public.

Initial Regulatory Flexibility Act

Pursuant to the Regulatory Flexibility Act of 1980, the FCC's initial analysis is as follows:

Need and Purpose of This Action

The proceeding is initiated to obtain comment regarding possible modification of the Commission's nondiscriminatory accounting rate, equal division of tolls or proportionate return traffic requirements, and/or conditioning of section 214 authorizations, where facilities-based competition for international services is available in foreign countries. The Commission seeks recommendations on the most appropriate methods of implementing any such modifications that might be adopted.

Summary of Second Further Notice of Proposed Rulemaking

The Second Further Notice of Proposed Rulemaking requests comment on whether allowing some flexibility in our nondiscriminatory accounting rate, division of tolls, or proportionate return policy might be an appropriate means of achieving lower accounting rates as facilities-based competition is introduced in foreign countries. Specifically, the Commission invites

suggestions on what modifications to its International Settlements Policy (ISP) might best achieve this goal. It also requests comment on whether conditioning Section 214 authorizations where a competitive environment exists in a foreign country might help to reduce accounting rates, and, if so, how this goal might be achieved.

Public Benefits

The Commission is open to the possibility that, where there is a competitive market in a foreign country, its ISP requirements may be relaxed in an effort to facilitate lower accounting rates and ultimately lower outpayments to foreign correspondents, which could ultimately result in lower collection rates for U.S. consumers.

Ordering Clauses

Accordingly, *It is Ordered* that notice is hereby given of the proposed regulatory action described above, and that comment is sought on these proposals.

For further information on this item contact Teresa Marrero, Attorney, Common Carrier Bureau, (202) 632–3214.

Federal Communications Commission.

Donna R. Searcy,

Secretary.

[FR Doc. 93–447 Filed 1–8–93; 8:45 am]

BILLING CODE 6712–01–M

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47 CFR Part 76

[MM Docket No. 92–264, FCC 92–542]

Cable Television Services; Implementation of the Cable Television Act, Horizontal and Vertical Ownership Limits, Cross-Ownership Limitations and Anti-Trafficking Provisions

AGENCY: Federal Communications Commission.

ACTION: Proposed rule.

SUMMARY: The Commission, by this Notice of Proposed Rule Making and Notice of Inquiry (Notice), seeks to implement sections 11 and 13 of the Cable Television Consumer Protection and Competition Act of 1992 (1992 Cable Act). In this Notice, the Commission solicits comment on the interpretation and implementation of the cross-ownership and anti-trafficking provisions of the 1992 Cable Act. The Commission also solicits comment on the adoption of limits on horizontal concentration and vertical integration in the cable industry. The action is taken in order to comply with the 1992 Cable Act.

DATES: Comments are due by February 9, 1993, and reply comments are due by March 3, 1993.

ADDRESSES: Federal Communications Commission, Washington, DC 20554.

FOR FURTHER INFORMATION CONTACT: Jacqueline Chorney, Mass Media Bureau, Policy and Rules Division (202) 632–7792.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's Notice of Proposed Rule Making and Notice of Inquiry in MM Docket No. 92–264, FCC 92–542, adopted December 10, 1992, released December 28, 1992. The complete text of this document is available for inspection and copying during normal business hours in the FCC Reference Center, 1919 M Street, NW., room 239, Washington, DC, and also may be purchased from the Commission's copy contractor, Downtown Copy Center, at (202) 452–1422, 1990 M Street, NW., room 640, Washington DC 20554.

Synopsis of the Notice of Proposed Rule Making

1. The Commission, in accordance with the 1992 Cable Act, considers the interpretation and implementation of the cross-ownership and anti-trafficking provisions of the 1992 Cable Act. The Commission also considers adoption of limits on horizontal concentration and vertical integration in the cable industry.

2. Section 13 of the 1992 Cable Act adds a new section 617 to the Communications Act of 1934, as amended, which establishes a three-year holding requirement for cable systems. Section 11 of the Cable Act of 1992 establishes several restrictions on the ownership and sale of cable systems. First it modifies section 613(a) of the Communications Act of 1934, as amended, to prohibit the common ownership of a cable system and a multichannel multipoint distribution service ("MMDS") or a cable system and a satellite master antenna television service ("SMATV"), apart from the franchised cable service, within a franchise area. Section 11 of the new Act also amends section 613 of the Communications Act of 1934 by adding a new subsection (f)(1), which requires the Commission to conduct a proceeding:

(1) To prescribe reasonable limits on the number of cable subscribers a person can reach through cable systems owned by such person ("subscriber limits");

(2) To prescribe reasonable limits on the number of cable channels that can be occupied by a video programmer in which a cable operator has an ownership interest ("channel occupancy limits"); and

(3) To consider the necessity and appropriateness of imposing limitations on the degree to which "multichannel video programming distributors" may participate in the creation or production of video programming.

3. The MMDS and SMATV cross-ownership restrictions and the anti-trafficking rule contain no specific effective date and, therefore, became effective on December 4, 1992 (the effective date of the 1992 Cable Act). However, the provision of the anti-trafficking rule which establishes a 120-day limit on the amount of time that a franchise authority has to disapprove a request to transfer a cable system, will not become effective until the Commission adopts regulations regarding the information required in connection with such requests. In this proceeding, the Commission seeks to identify the proper interpretation of the anti-trafficking rule and to establish an appropriate system of implementation.

4. The 1992 Cable Act and its legislative history demonstrate Congress' concern regarding horizontal concentration and vertical integration in the cable television industry. Congress, through the vertical and horizontal limits required by section 11 of the 1992 Cable Act, sought to prevent large, vertically integrated cable systems from creating barriers to entry of new programmers and from causing a reduction in the number of media voices available to consumers through cable television. In addition, the 1992 Cable ACt indicates Congress' conclusion that increasing vertical integration provides cable operators with both the incentive and the ability to favor their affiliated programmers over other programming services, and that vertically integrated program suppliers have the incentive and ability to favor their affiliated cable operators over other cable operators and programming distributors using alternative technologies. In establishing the subscriber limits and channel occupancy restrictions required by the 1992 Cable Act, the Commission must balance these concerns expressed by Congress with the efficiencies and benefits to be gained by increased concentration and integration.

Sales of Cable Systems

5. Section 13 of the 1992 Cable Act establishes a three-year holding period for cable systems. Under the cable anti-trafficking rule, with certain exceptions, "no cable operator may sell or otherwise transfer ownership in a cable system within a 36-month period following

either the acquisition or initial construction of such system by such operator." For purposes of this provision, multiple system transfers which provide for the subsequent transfer of one or more such systems shall be considered part of the initial transaction.

6. Jurisdiction and Enforcement. Because local franchising authorities are responsible for awarding cable franchises, and for approving sales and transfer of such franchises, the Commission tentatively concludes that local franchising authorities can most efficiently monitor and enforce compliance with the anti-trafficking restriction. The Commission proposes to require cable operators seeking to transfer ownership in cable system to certify to the franchise authority that the proposed transfer satisfies the three-year holding requirement or is exempt under one of the exceptions contained in the rule. If the terms of the franchise agreement do not require approval of the franchise authority for transfer or assignment of a cable system, the cable operator should nonetheless certify to the franchising authority that such transfer is not in violation of the three-year holding requirement. Operators making such a certification will be presumed to be in compliance with the anti-trafficking rule unless the local franchise authority finds to the contrary. Alternatively, a cable operator may seek a waiver of the anti-trafficking rule from the Commission in appropriate circumstances. Commenters are asked to address whether these procedures are suitable for enforcing the anti-trafficking rule. The Commission also invites comment regarding how these procedures could best be crafted.

7. Transfer of Ownership. The Commission seeks comment on the appropriate interpretation of "transfer of ownership in a cable system" for purposes of applying the three-year holding period. The Commission also asks commenters to identify the types of transactions Congress sought to include within the anti-trafficking rule. In commenting on this matter, parties are asked to consider existing Commission rules restricting the transfer of broadcast licenses and construction permits. Specifically, note the Commission's one-year holding requirement applicable to broadcast licenses obtained through the comparative hearing process or pursuant to the Minority Ownership Policy. See 47 CFR 73.3597(a)(4). Pursuant to section 310(d) of the Communications Act of 1934, this one-year holding requirement does not apply to transfers to ownership interests which do not result in a transfer of control or assignment of license. Commenting parties are asked to address whether "transfer of ownership in a cable system" should be defined by references to the broadcast transfer of control standards implemented pursuant to section 310(d) of the Communications Act of 1934.

8. The Commission tentatively concludes that its broadcast transfer of control standards are appropriate to implement the cable anti-trafficking rule. Commenters are asked to indicate whether those standards will provide cable operators and franchise authorities with sufficient guidance regarding application of the anti-trafficking restriction, and encompass the types of transfers that Congress intended to restrict. Alternatively, it may be preferable to establish a fixed transfer of ownership threshold encompassing only changes in who controls 50% or more of the outstanding equity in a cable system. The Commission invites commenters to indicate whether this definition would be consistent with the objectives of the anti-trafficking rule or whether a standard based on some lesser percentage of ownership (e.g., 25%, 30%, 40%) would be more appropriate. Finally, the attribution criteria contained in § 73.3555 (Notes) of the Commission's Rules could also be used to define ownership interests subject to the anti-trafficking rule. The Commission invites comment regarding which of these standards would be most appropriate in implementing the cable anti-trafficking provision in accordance with Congressional intent.

9. The Commission also invites comment regarding what, if any, procedures should be established for resolution of complaints arising from determinations under this provision. Commenters should indicate whether the Commission or the federal or state courts should resolve complaints involving the application of the anti-trafficking rule to a particular transaction. Preliminarily, the Commission believes that such complaints should be resolved at the local level, either according to relevant procedures contained in the franchise agreement or by commencement of an action in the state or federal courts. Alternatively, commenters are asked to indicate whether the Commission should establish specific procedures to be followed in resolving disputes regarding application of the anti-trafficking rule to ensure consistency in the interpretation of the rule and to allow for participation by all interested parties. If such procedures are appropriate, commenters should indicate whether the provisions of § 76.7 of the Commission's Rules (the special relief rules), or some modified form of these procedures, would be acceptable. Commenters should also address what, if any, sanctions would be appropriate for transfers in violation of the anti-trafficking rule. The Commission notes that although some sanctions such as forfeiture may be applicable (via section 503 of the Communications Act), the Commission does not interpret the anti-trafficking provision as necessarily requiring reversal of transfers of ownership based on good faith interpretation of the rule, where such transfers are subsequently found to violate the rule.

10. Regarding computation of the three-year holding period, commenters are requested to specify what dates should be used when calculating the period between initial construction and transfer or assignment of a cable system. Commenters should also specify what dates should apply when calculating the period between initial acquisition of a cable system and transfer of assignment of such system. The Commission further seeks comment regarding the appropriate treatment of multiple system owner (MSO) transfers under this provision. Commenters should indicate what procedures the Commission should establish for determining compliance with the anti-trafficking provision for transfers or assignments of MSOs.

11. Exceptions. The Cable Act of 1992 establishes three exceptions to the anti-trafficking restriction. The Commission seeks to clarify implementation of these exceptions, and asks commenters to indicate what types of transactions are contemplated by each exception. The first exception excludes any transfer or assignment of a cable system, which is not subject to Federal income tax liability. The Commission tentatively finds that this exemption applies to (a) transactions involving tax certificates issued by the Commission pursuant to section 1071 of the Internal Revenue Code ("Code"), which allows deferral of gains taxes for businesses acquired by minorities, (b) so-called "tax free" exchanges of assets under section 1031 of the Code, and (c) "tax free" reorganizations under section 368 of the Code. The Commission invites comment regarding whether the payment of cash or other taxable consideration, to equalize the value of assets in like system exchanges, should render such a transaction ineligible for this exception. Commenters are requested to address these tentative conclusions and to identify any other transactions that may qualify for this exception.

12. The second exception excludes any sale required by operation of any law, or by any act of any Federal agency, any state or political subdivision thereof, or any franchising authority. The Commission believes that this exception was intended primarily to enable franchise authorities or other government entities to require the transfer of a cable system that is in violation of its franchise agreement or that is otherwise providing inadequate service. This exception may also be interpreted to include transfers of cable systems in the context of bankruptcy proceedings or other types of receivership. The Commission seeks comment on these interpretations and on any other types of transactions that may be contemplated by this exception. The Commission further asks commenters to indicate whether sales of municipally operated cable systems were also intended to be exempt from the anti-trafficking rule pursuant to this exception.

13. Third, the 1992 Cable Act exempts any sale, assignment or transfer to one or more purchasers, assignees or transferees controlled by, controlling, or under common control with the seller, assignor or transferor. The Commission believes that this exception was intended to apply to *pro forma* transfers as defined in § 73.3540(f) of the Commission's Rules. The Commission asks commenters to indicate what other inter-company transfers should be included within this exception. The Commission does not interpret this provision as requiring a new three-year holding period to commence following each transfer to an affiliate entity. The Commission also tentatively concludes that the acquisition date following a transfer between affiliated entities should relate back to the original date such system was constructed or acquired by the affiliated transferor.

14. Finally, the Commission initially finds that cable operators seeking to transfer ownership of a cable system prior to the expiration of the statutory three-year holding period should submit to the franchise authority all information necessary to support a certification that the proposed transfer satisfies one of the stated exceptions. Commenters are asked to indicate what types of information should be required in order to establish eligibility under each of these exceptions.

15. Waivers. The 1992 Cable Act empowers the Commission, consistent with the public interest, to waive the three-year holding requirement. In connection with the general waive authority granted by this provision, comment is solicited on whether to establish specific waiver criteria and, if specific waiver criteria are adopted, what types of showing should be required. The 1992 Cable Act directs the Commission to use its waiver authority to permit "appropriate transfers in cases of default, foreclosure, or other financial distress," but it does not define the term "financial distress." The Commission invites comment on whether criteria contained in § 73.3597(a)(4) of the Commission's Rules should be used to define "financial distress" or whether some other standard would be more appropriate in this context.

16. If approval of the franchise authority is required in connection with the transfer of a cable system, the 1992 Cable Act provides that the Commission shall not waive such requirements unless the franchise authority has approved the proposed transfer. The Commission proposes that in such circumstances, waivers may nonetheless be granted prior to franchise authority consideration, provided such waivers are contingent upon ultimate approval by the franchising authority. The Commission seeks comment on whether such conditional waivers would be appropriate under the 1992 Cable Act and on whether franchise authority approval should create a presumption that the Commission will grant a waiver authorizing a particular transfer.

17. Limitation on Duration of Franchise Authority Power to Disapprove Transfers. Subsection (e) of the anti-trafficking rule limits the amount of time that a franchising authority has to disapprove a transfer of a cable system and also indicates that the Commission will establish regulations indicating the information that will be required in connection with such a request for transfer. The Commission seeks comment regarding what type of informational requirements to establish in connection with transfer requests. The Commission seeks to establish a minimum standard for such informational requirements and allow franchise authorities to request any additional information that may be necessary to evaluate a particular transfer.

MMDS/SMATV Cross-Ownership Prohibition

18. Section 11 of the 1992 Cable Act amends section 613(a) of the Communications Act of 1934 to add a prohibition against common ownership of a cable system and either an MMDS or a SMATV service in its franchise area. The provision is intended to address Congress' concern that common ownership of different means of video distribution may reduce service competition.

19. The Commission has already adopted regulations implementing a cable/MMDS cross-ownership prohibition in a recently concluded rulemaking initiated to facilitate the provision of "wireless cable" service to the public.[1] The recently adopted rules "prohibit, directly or indirectly, ownership interests in, control of, or leasing of * * * MMDS * * * by cable television companies in geographic areas which overlap the * * * MMDS protected service areas * * * for cable franchise areas lacking two or more competing cable television companies." The Commission's Rules include the attribution rules and definitions of "control," "areas" and "overlap" necessary to effectuate this prohibition. 47 CFR 21.912. The Commission's Rules also provide for limited exceptions to the general prohibition which the Commission has already determined will be in the public interest, i.e., a rural exception (47 CFR 21.912(d)(1) and a local programming exception (47 CFR 21.912(e)).

20. The Commission believes these recently adopted rules are consistent with and effectively implement the cross-ownership prohibitions of the 1992 Cable Act as regards the MMDS service and that the same rules and their implementing criteria are appropriate for the cross-ownership prohibitions as they relate to SMATV.[2] Commenters are invited to address these tentative conclusions.

21. The 1992 Cable Act provides for the grandfathering of existing cross-ownership situations that existed on October 5, 1992. Note that the current Commission Rules grandfathered those cable/MMDS cross-ownership interests that existed on their effective date. In view of the Commission's tentative position that the exiting Rules fulfill the 1992 Cable Act's mandate with respect to MMDS, the Commission proposes to continue to grandfather only those cable/MMDS cross-ownership interests. No additional cable/MMDS cross-ownership relationships would be grandfathered pursuant to the terms of

[1] Report and Order in Gen. Docket Nos. 90–54 and 80–113, 55 FR 46006, October 31, 1990; Order on Reconsideration in Gen. Docket Nos. 90–54 and 80–113, 56 FR 57596, November 13, 1991; Second Report and Order in Gen. Docket No. 90–54, 56 FR 57808, November 4, 1991.

[2] The Commission has not determined whether, and to what extent, the existing cable/MMDS cross-ownership rules and the 1992 Cable Act cross-ownership restriction apply to Local Multipoint Distribution Service ("LMDS"). This issue is addressed more fully and comments are requested in the Notice of Proposed Rulemaking in CC Docket 92–297, released December 10, 1992.

the 1992 Cable Act in any event. Cable/SMATV cross-ownership interests will be grandfathered as of October 5, 1992. Furthermore, the 1992 Cable Act permits the Commission to waive the statutory prohibition against cable/MMDS and cable/SMATV cross-ownership to the extent that it is determined that cross-ownership is needed to ensure that all significant portions of a franchise area are able to obtain video programming. Comment is requested on whether the existing public interest waiver standard for cable/MMDS situations is sufficient or whether additional rules or criteria for such waivers in the context of this proceeding should be established. If the Commission adopts such criteria, what types of information would be needed to indicate that cross-owned systems serving the same franchise area provide the only means to distribute multichannel video program service to the public? Finally, the Commission notes that the rules and procedures specified in § 76.7 are applicable for the filing of most requests for waiver of the cable television rules. Should waivers of these cross-ownership rules also be subject to these provisions? Are there any modifications needed to implement these specific cross-ownership waiver requests?

22. With respect to enforcement of the cross-ownership provision, the Commission believes it appropriate to establish procedures for consideration of complaints. The Commission seeks comment regarding what procedures should be adopted to allow participation by all interested parties, and on whether to apply the provisions of § 76.7 of the Commission's Rules (the special relief rules), or some modified form of these procedures, in such cases. Alternatively, cable operators could be required to provide information regarding ownership of MMDS services or SMATV systems in filings required of cable systems, such as the annual Form 325 or on CARS license applications. The Commission asks commenters to consider whether this type of reporting requirement is necessary. In this regard, commenters are asked to suggest the sort of specific information that would be useful.

Subscriber Limits

23. In order to enhance competition, section 11 of the 1992 Cable Act requires the Commission within one year to conduct a proceeding intended to "prescribe reasonable limits on the number of cable subscribers a person is authorized to reach through cable systems owned by such person or in which such person has an attributable interest."

24. Commenters are asked to consider, in commenting on Section 11, the public interest objectives delineated in the 1992 Cable Act:

(A) To ensure that no cable operator or group of cable operators can unfairly impede the flow of video programming from the programmer to the consumer;

(B) To ensure that cable operators do not favor affiliated video programmers in determining carriage and do not unreasonably restrict the flow of video programming of unaffiliated video programmers to other video distributors;

(C) To take account of the market structure, ownership patterns, and other relationships of the cable industry, including the market power of the local franchise, joint ownership of cable systems and video programmers, and the various types of non-equity controlling interests;

(D) To take into account any efficiencies and other benefits that might be through increased ownership or control;

(E) To ensure that such rules and regulations reflect the dynamic nature of the communications marketplace;

(F) To impose limitations that will not prevent cable operators from serving previously unserved rural areas; and

(G) To impose limitations that will not impair the development of diverse and high quality programming.

25. In prescribing subscriber limits, the Commission must, as a preliminary matter, determine the markets in which such subscriber limits should be established. Horizontal concentration may be measured on a local, regional or national basis. The Commission asks commenters to indicate whether regional concentration in any market is sufficient to allow MSOs to exercise undue market power in competing for program acquisition or advertising. Commenters should also describe any efficiencies, economies of scale, and other benefits which result from regional and national concentration. Commenters are asked to indicate whether both regional and national subscriber limits are necessary or appropriate to execute the objectives of the 1992 Cable Act. Commenters are also asked to indicate whether it would be appropriate in calculating compliance with the national subscriber limits to subtract the number of subscribers reached or homes passed by cable systems in areas where effective competition is established.

26. Under the 1992 Cable Act, the Commission may prescribe subscriber limits either as a share of cable subscribers or as a share of homes passed. Commenters should address which of these measures should be used to implement the subscriber limits established in this proceeding. The Commission recognizes that subscriber-based measures have traditionally been used for purposes of analysis. Nonetheless, the Commission believes that homes passed may be a more appropriate and practical measure for this purpose, since it encompasses all television households for which a particular cable operator provides access to cable programming. For this reason and to provide consistency in the interpretation of our rules, the Commission proposes to use a homes passed measure to implement the cable subscriber limits established in this proceeding and seeks comment on this proposal.

27. Commenters are also asked to indicate what percentage of homes passed nationally would constitute a reasonable limit on horizontal concentration. In this regard, commenters should indicate at what percentage of homes passed a single MSO could preclude the success of a new cable service. Are there recent examples of this type of conduct? How many subscribers must be cleared nationally to launch and sustain a new cable programming service? Does the number of subscribers needed vary depending on the type of programming involved? Is it relevant that the Commission's broadcast multiple ownership rules limit the audience reach of television stations in which a person can hold an attributable interest to 25% of television households nationwide? It should also be noted that Commission Rules also provide for increased ownership of broadcast stations representing up to 30% of the television households nationwide if the additional stations are minority owned. The Commission seeks comment on whether to adopt a similar provision in the cable context. The Commission also notes that, under its rules, national television networks are also permitted to own cable systems which reach 10% of the homes passed nationally. Should this figure, which takes into consideration the national audience reach and ability to control programming associated with a broadcast network, serve as a guide in crafting national ownership limits for cable systems? Finally, commenters are asked to indicate whether divestiture should be required for any MSO which exceeds the limit ultimately adopted on the number of homes passed nationally.

28. The attribution criteria contained in § 73.3555 of the Commission's Rules may be useful for determining

ownership in connection with the subscriber limits ultimately established. It should be noted, however, that these attribution criteria were intended to include ownership thresholds which may impart the ability either to influence or control management or programming decisions of a broadcast licensee, and consequently these criteria may not be appropriate to address the concerns at issue in this proceeding. The Commission seeks comment regarding whether these attribution criteria (or a modified version thereof) are appropriate for implementing cable subscriber limits or whether some other attribution criteria would be more suitable. Commenters should also indicate if there are other types of ownership interests, such as non-equity interests, that should be cognizable for purposes of determining ownership under this provision.

29. Jurisdiction and Enforcement. The Commission tentatively concludes that reporting requirements may be unnecessary in connection with enforcing the subscriber limits ultimately adopted. In the alternative, the Commission believes that a system of certification may be an appropriate means of enforcing the subscriber limits imposed. The Commission may, for example, require cable operators upon transfer or assignment of a cable system to certify that such transfer will not result in ownership of cable systems exceeding the subscriber limits established by the Commission. Comment is invited on whether such a certification should be made to the local franchise authority having jurisdiction over the cable system being acquired, or to the Commission. If a system of certification is appropriate, comment is requested on whether all cable systems should be required to make the requisite certification or only the five or ten largest cable systems. The Commission also requests comment on whether such a certification is necessary at all, or whether, in the alternative, the Commission should enforce the subscriber limits on a complaint only basis. Commenters should also indicate if there are other more appropriate procedures to enforce the subscriber limits. The Commission further seeks comment on whether waivers or exceptions to the subscriber limits should be obtainable in appropriate circumstances.

30. The Commission, in compliance with the legislative history of the 1992 Cable Act, proposes to institute a review of the subscriber limits every five years to ensure that they continue to accurately reflect the objectives of the legislation and are reasonable under the prevailing market conditions. Commenters are asked to indicate whether such review procedures are adequate to ensure that subscriber limits continue to serve the objectives for which they were established.

Channel Occupancy Limits

31. Section 11 of the 1992 Cable Act requires the Commission within one year to "prescribe reasonable limits on the number of channels on a cable system that can be occupied by a video programmer in which a cable operator has an attributable interest."

32. Although the 1992 Cable Act does not indicate the ownership standard that should be applied in connection with channel occupancy limits, the Senate Report indicates that the Committee intended for the Commission to use the attribution criteria set forth in § 73.3555, or such other criteria as the Commission may deem appropriate in implementing channel occupancy limits. Comment is requested on whether the attribution criteria contained in § 73.3555 of the Commission's Rules, which are designed to identify ownership interests that afford influence or control over station operations or programming, are appropriate for this purpose. Should any modifications be made for purposes of determining ownership affiliations between cable operators and program services? In the event that the Commission increases the attribution threshold or otherwise modifies the attribution criteria as proposed in MM Docket No. 92–51, 7 FCC Rcd 2654 (1992), commenters should indicate whether the Commission should similarly modify those criteria for purposes of the cable ownership rules. Commenters are asked to address how application of these attribution rules would affect investment by cable operators in new cable programming services. Parties also are asked to indicate whether higher attribution thresholds are warranted in connection with this restriction in order to provide cable operators with the flexibility to continue investing in new cable programming services.

33. The Commission seeks comment on the procedures that should be used in calculating the cable channel occupancy limits ultimately adopted. The 1992 Cable Act and its legislative history are unclear on this issue. The Senate Report suggests that the Commission may establish such limits based on the number of activated channels, less the number of over-the-air broadcast channels, public, educational, governmental and leased access channels carried. Under this approach, using a hypothetical 20% channel occupancy limit, a system with 54 channels, 14 of which are over-the-air channels, would have a channel occupancy limit of 8 channels for MSO affiliated programming. Parties are requested to comment on whether these procedures for calculating channel capacity are appropriate and reasonably serve the objectives of the legislation.

34. In addressing this issue, commenters should consider that one of the objectives of vertical ownership limits was to ensure that unaffiliated cable programmers have a reasonable opportunity to gain access to vertically integrated cable systems. In this regard, the Commission questions whether it is appropriate to subtract the over-the-air broadcast channels, and public, educational, governmental and leased access channels in calculating a system's channel capacity. Broadcast channels contain programming that is competitive with cable programming, and leased access channels provide alternative outlets for unaffiliated video programmers. In addition, the commercial and educational broadcast channels are subject to must-carry requirements, pursuant to section 4 of the 1992 Cable Act. To the extent that carriage of these signals is mandatory, the Commission questions whether it is appropriate for such channels to be subtracted from the total number of channels in calculating channel occupancy limits. Comments are invited to address how such a procedure would serve the statutory objectives of increasing diversity and expanding the number of cable choices available to consumers. The Commission further seeks comment regarding how pay channels, such as HBO, Showtime and pay-per-view channels, should be treated for purposes of calculating the channel occupancy limits, since not all subscribers receive these channels. In addition, what provisions should be made for "multiplexing" of pay channels, where the same programming is shown on several different channels at different times? Commenters should also indicate whether channel occupancy limits apply only to vertically integrated national programming networks, or whether such limits should also apply to vertically integrated regional programming networks.

35. It is unclear from the statutory language and the legislative history how Congress intended such channel occupancy limits to be applied. For example, it is unclear whether such limits were meant to apply only to video programmers affiliated with the particular cable operator or whether

such limits were intended to apply to any cable affiliated video programmer. It is similarly unclear if the latter interpretation is used, whether the channel occupancy limit should be applied so that a total of eight channels could be occupied by all vertically integrated programming combined or whether such a limit should be applied so that the programming of each MSO could occupy up to the maximum of eight channels on such a system. The Senate Report could be read to suggest that the channel occupancy limits should apply to the number of channels that any cable operator can devote to any vertically integrated programming, regardless of whether a programmer is affiliated with that particular cable operator. Commenters are asked to indicate how the channel occupancy limits we ultimately adopt should be applied to most effectively address Congress' concerns.

36. Given the uncertainty surrounding the application of the channel occupancy limits, the Commission believes that the more reasoned approach is to apply such limits only to video programmers affiliated with the particular cable operator. The Commission notes that such an interpretation would be consistent with Congress' objectives of increasing diversity and expanding the number of voices available to consumers. Moreover, such an interpretation addresses Congress' goal of reducing the ability and the incentive of cable operators to favor their own affiliated video programmers. Commenters are asked to indicate whether this proposal is appropriate. In considering this issue, commenters should consider whether vertically integrated programing has an adverse effect on diversity.

37. The Commission also seeks comment on how to determine what constitutes a reasonable channel occupancy limit. What criteria should be used to establish such limits? Are there other regulatory analogies that would be useful in determining what percentage of a cable system's channels should be occupied by vertically integrated program services? In addressing this issue, commenters are asked to consider the vertical relationships and ownership patterns that were reported in appendix G to the 1990 Cable Report. Commenters are asked to provide relevant information, such as the average number of channels occupied by vertically integrated program services. Commenters are also requested to address how the availability of leased access channels should affect the establishment of channel occupancy limits. Commenters are asked to indicate the degree to which vertical integration threatens the ability of rival programming services to obtain cable carriage. It is the Commission's intention to establish a channel occupancy limit that maximizes the number of voices that are available to cable viewers without impairing the ability or incentive of cable operators to invest in new and existing programming services. In this regard, the Commission notes that MSO investment has been essential to the development and continuation of many of the most popular and innovative programming services.

38. The Commission tentatively concludes that it should establish a percentage limit on the number of channels that can be occupied by vertically integrated programming services. Commenters are asked to indicate what percentage of cable channels would be most appropriate to prevent competitive abuses without discouraging investment relationships between cable operators and program services. In suggesting the appropriate percentage limit, commenters are asked to consider the other structural and behavioral restrictions included in sections 12 and 19 of the 1992 Cable Act. Moreover, commenters should consider the must-carry and leased access requirements applicable to cable systems in commenting on this issue.

39. The Commission also seeks comment on what effect emerging technologies such as digital signal compression and fiber optic cable should have on the channel occupancy limits. The Commission proposes to establish a threshold beyond which the channel occupancy limits would not be applicable, and asks commenters to indicate the appropriate number of channels for establishing such a threshold. The Commission suggests that the channel occupancy limits would apply only for channels up to this threshold, with no limits applicable for channels in excess of the threshold.

40. Finally, the Commission seeks comment on whether channel occupancy limits should be phased out in communities where effective competition has developed. Once effective competition has been established and a cable operator no longer occupies a program access bottleneck position, channel occupancy limits may no longer be necessary or desirable. With such developments, the incentive and ability of a cable system to favor its own programming over unaffiliated programming is diminished, and alternative outlets for programming should be available to the public. In seeking comment on this issue, we ask whether phasing out channel occupancy limits under these conditions is consistent with Congressional intent. In addition, we ask whether channel occupancy limits should be lifted for any cable system that meets the effective competition criteria, or whether only certain of those criteria would justify removing the limits.

41. Jurisdiction and Enforcement. The Commission proposes that the local franchise authorities have primary responsibility for enforcement of the channel occupancy limits, as they are most familiar with the channel capacity and programming services carried on the systems within their jurisdiction. Because the Commission seeks to minimize the burden imposed on local franchise authorities and cable operators by these restrictions, it is proposed that such channel occupancy limits should be enforced by certification. Accordingly, cable operators would be required to certify annually to the franchise authority that they are in compliance with the channel occupancy limits ultimately adopted. In order to ensure continuous compliance, cable operators would be obligated to notify the franchise authority within 30 days of any changes during the course of the year which would affect compliance with the channel occupancy restrictions. In addition, a franchise authority would be entitled to request any additional information it determined was reasonably necessary to establish the accuracy of a system's certification, if such certification was challenged. The Commission also proposes to grandfather any existing vertical relationships which exceed the channel occupancy limits at the time such limits are adopted. Comment is invited on this proposal and on whether these procedures are appropriate to ensure compliance with the channel occupancy limits.

Participation in Program Production

42. Section 11 of the 1992 Cable Act also requires the Commission to consider the necessity and appropriateness of imposing limits on the degree to which multichannel video programming distributors ("multichannel distributors") may engage in the creation or production of video programming. As previously stated in this Notice, the 1992 Cable Act mandates that the Commission establish certain structural limits on the development of horizontal and vertical integration in the cable industry. In addition to the structural limits addressed in this proceeding, the 1992 Cable Act establishes certain behavioral restrictions which prohibit

anticompetitive conduct by cable operators in the acquisition of programming. In view of the structural and behavioral restrictions already required under the 1992 Cable Act, the Commission seeks comment on whether additional restrictions on the ability of multichannel distributors to engage in the creation or production of video programming are warranted. The Commission believes that at the present time the objectives of such a restriction may be fully addressed by the other provisions of section 11, section 12, and section 19 of the 1992 Cable Act. Commenters who believe that further restrictions are warranted should indicate what, if any, additional benefits would be achieved by imposing such additional restrictions and what effect they would have on the growth and development of new programming services.

Administrative Matters

Initial Regulatory Flexibility Analysis

Pursuant to the Regulatory Flexibility Act of 1980, the Commission finds:

43. Reason for the Action: The purpose of this Notice is to establish rules and regulations in accordance with the Cable Television Consumer Protection and Competition Act of 1992 relating to the development of horizontal and vertical ownership limits and implementation of cross-ownership and anti-trafficking provisions.

44. Objective of This Action: The 1992 Cable Act and the subsequent actions to implement it are intended to encourage competition in the cable industry and prevent the exercise of undue market power by horizontally or vertically integrated cable systems. This action is meant to clarify and the interpretation and implementation of sections 11 and 13 of the 1992 Cable Act. This proceeding will codify the statutory anti-trafficking restriction and the cross-ownership restriction. This proceeding will also establish subscriber limits and channel occupancy limits required by the 1992 Cable Act.

45. Legal Basis: Authority for the actions proposed in this Notice may be found in sections 4 and 303, 613, and 617 of the Communications Act of 1934, as amended, 47 U.S.C. 154 and 303, 533 and 537.

46. Reporting, Recordkeeping, and Other Compliance Requirements Inherent in the Proposed Rule: This Notice proposes to implement new certification and filing requirements applicable to cable systems, in order to ensure compliance with the proposed rules.

47. Federal Rules Which Overlap, Duplicate, or Conflict With the Proposed Rule: None.

48. Description, Potential Impact and Number of Small Entities Involved: Approximately 11,000 existing cable systems of all sizes may be affected by the proposals contained in the Notice. In addition, an unknown number of video programming sources may be affected.

49. Any Significant Alternatives Minimizing the Impact of Small Entities and Consistent With the Stated Objectives: The purpose of this Notice is to seek comment on issues including alternatives that would minimize the impact on small entities.

50. As required by section 603 of the Regulatory Flexibility Act, the FCC has prepared an initial regulatory flexibility analysis (IRFA) of the expected impact of these proposed policies and rules on small entities. Written public comments are requested on the IRFA. These comments must be filed in accordance with the same filing deadlines as comments on the rest of the Notice of Proposed Rule Making and Notice of Inquiry, but they must have a separate and distinct heading designating them as responses to the regulatory flexibility analysis. The Secretary shall cause a copy of this Notice of Proposed Rule Making and Notice of Inquiry, including the initial regulatory flexibility analysis, to be sent to the Chief Counsel for Advocacy of the Small Business Administration in accordance with section 603(a) of the Regulatory Flexibility Act, Public Law 96–354, 94 Stat. 1164, 5 U.S.C. section 601 *et seq.* (1981).

Ex Parte

51. This is a non-restricted notice and comment rule making proceeding. *Ex parte* presentations are permitted, except during the Sunshine Agenda period, provided they are disclosed as provided in the Commission's Rules. See generally 47 CFR 1.1202, 1.1203, and 1.1206(a).

Comments

52. Pursuant to applicable procedures set forth in §§ 1.415 and 1.419 of the Commission's Rules, 47 CFR 1.415 and 1.419, interested parties may file comments on or before February 9, 1993, and reply comments on or before March 3, 1993. To file formally in this proceeding, you must file an original plus four copies of all comments, reply comments, and supporting comments. If you want each Commissioner to receive a personal copy of your comments, you must file an original plus nine copies. You should send comments and reply comments to Office of the Secretary, Federal Communications Commission, Washington, DC 20554. Comments and reply comments will be available for public inspection during regular business hours in the FCC Reference Center, room 239, Federal Communications Commission, 1919 M Street, NW., Washington, DC 20554.

Ordering Clauses

53. Authority for this Notice of Proposed Rule Making is contained in sections 4(i) and (j), 303, 613 and 617 of the Communications Act of 1934, as amended.

List of Subjects in 47 CFR Part 76

Cable television.

Federal Communications Commission.

Donna R. Searcy,

Secretary.

[FR Doc. 93–448 Filed 1–8–93; 8:45 am]

BILLING CODE 6712-01-M

INTERSTATE COMMERCE COMMISSION

49 CFR Part 1312

[Ex Parte No. MC–211]

Revision of Tariff Regulations—Indexes

AGENCY: Interstate Commerce Commission.

ACTION: Advance notice of proposed rulemaking.

SUMMARY: The Commission is considering whether there is a need to reimpose requirements for tariff indexes, and if so, what kinds of indexes should be required. Because many tariffs now on file contain thousands of pages but no indexes, the rates applicable to particular shipments can be difficult to determine. Indexes may improve the public's ability to determine the rates which are contained in the tariffs and which are therefore applicable by law.

DATES: Comments are due on March 8, 1993.

ADDRESSES: Send comments (an original and 10 copies) referring to Ex Parte No. MC–211 to: Interstate Commerce Commission, Office of the Secretary, Case Control Branch, Washington, DC 20423.

FOR FURTHER INFORMATION CONTACT: Larry Herzig, (202) 927–5180. (TDD for hearing impaired (202) 927–5721).

SUPPLEMENTARY INFORMATION: In Revision of Tariff Regulations, All Carriers, 1 I.C.C.2d 404 (1984), the Commission adopted new tariff

publishing rules. In so doing, the Commission decided to remove the rule requiring indexing. First, the Commission believed that carriers would continue to publish indexes if they were necessary for marketing reasons. Second, a high volume of change in tariff matter would make indexes difficult to maintain. Finally, the requiring of indexes seemed unnecessary and burdensome because if indexes were useful competition would force carriers to provide them. It now appears that indexes may be important and useful but that carriers are not providing them. The purpose of this proceeding, initiated in part because of a request from Congress that we do so,[1] is to determine if there is a need for reimposing requirements for tariff indexes, and if so, what kinds of indexes we should require.

The primary purpose behind tariffs is to inform all interested parties of the services, practices and rates offered to the public by common carriers. A secondary purpose is to protect shippers by insuring that any rates and related provisions negotiated with carriers are honored. In order to implement these purposes, a shipper must be able to locate a given rate in a carrier's tariff, not only the rate covering the shipper's own traffic but also the rates and provisions covering a competitor's traffic. It would appear to be an undue burden on tariff users for carriers to construct tariffs without affording users the means for determining where they can obtain all information required to be on file under the statute and our regulations.

Our files indicate that many carriers have not found it in their interest to publish and maintain indexes in their tariffs. Moreover, there are tariffs on file with this Commission which contain well over 100,000 pages, without indexes, which are not arranged in any logical order. Needless to say, it is very difficult to locate provisions contained in these tariff publications. While maintaining comprehensive indexes may indeed be a burden on carriers, the present circumstances suggest that reimposing the indexing requirement would be in the public interest.

While indexes may well be necessary for commodity rate tariffs and tariffs naming specific discounts, they would appear not to be necessary for other types of tariffs which are arranged in a manner which allows a tariff user to easily find information. For example, in certain class rate tariffs the origin and destination points are listed alphabetically or geographically. Also, the classification assigning class ratings to all commodities has an index. Historically, the Commission's tariff publishing regulations indexes only for commodity rate tariffs, because discounts were not a usual form of tariff publication. At the time discounts were beginning to proliferate, the Commission removed the requirement for indexes.

After receipt of comments, we may propose regulations which would require that tariffs contain indexes when they are arranged in a manner which does not allow a tariff user to find information quickly, accurately, and completely. In the past our regulations have required every filed common carrier tariff to contain indexes of contents, commodities, origin points, and destination points. It has now become apparent that some sort of index may also be needed for tariffs which contain service, practices, or rate information which is applicable only to individual customers or accounts. Further, it may be appropriate to require that all carriers file an index listing the tariffs they have filed with the Commission and which also lists the rate bureau tariffs that the carriers participate in.

However, before we make proposals we would like to consider the views of all parties which may be interested in this issue. Comments concerning the need to reimpose a requirement of indexing, as well as the types of indexes which are needed in today's competitive environment are solicited.

Regulatory Flexibility

Because this not a notice of proposed rulemaking within the meaning of the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), we need not make, at this time, the small business impact examination required by that Act. Nevertheless, we welcome any comments regarding the small entities considerations embodied in that Act. If we decide to issue a notice of proposed rulemaking, we will conduct an appropriate Regulatory Flexibility Act examination at that time.

Environmental Statement

This action will not significantly affect either the quality of the human environment or the conservation of energy resources.

Authority: 49 U.S.C. 10761(a) and 10762.

List of Subjects in 49 CFR Part 1312

Motor carriers, Moving of household goods, Pipelines.

Decided: December 23, 1992.

By the Commission, Chairman Philbin, Vice Chairman McDonald, Commissioners Simmons and Phillips.

Sidney L. Strickland, Jr.,

Secretary

[FR Doc. 93–488 Filed 1–8–93: 8:45 am]

BILLING CODE 7035-01-M

[1] Senate Report No. 102–351, dated July 30 1992, and accompanying the U.S. Department of Transportation and Related Agencies Appropriations Bill, 1993

Notices

Federal Register
Vol. 58, No. 6
Monday, January 11, 1993

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF COMMERCE

Bureau of Export Administration

[Docket No. 921246–2346]

Foreign Availability Assessment: Advanced High Speed Modems

AGENCY: Office of Foreign Availability, Bureau of Export Administration, Commerce.

ACTION: Notice of Initiation of an Assessment and Request for Comments.

SUMMARY: The Office of Foreign Availability (OFA) is providing notice that it has initiated an assessment of foreign availability of advanced high speed modems operating above the current control level of 9,600 bits per second to both noncontrolled and controlled countries. OFA will assess foreign availability under part 791 of the Export Administration Regulations (EAR). OFA is seeking public comments on the foreign availability of these items worldwide.

DATES: The period for submission of information will close on February 10, 1993.

ADDRESSES: Submit information relating to this foreign availability assessment to: Steven C. Goldman, Office of Foreign Availability, Bureau of Export Administration, U.S. Department of Commerce, room 1087, 14th Street and Pennsylvania Avenue, NW., Washington, DC 20230.

The public record concerning this notice will be maintained in the Bureau of Export Administration's Freedom of Information Record Inspection Facility, room 4518, U.S. Department of Commerce, 14th Street and Pennsylvania Avenue, NW., Washington, DC 20230.

FOR FURTHER INFORMATION CONTACT: Laure Ferguson, Office of Foreign Availability, Department of Commerce, Washington, DC 20230, Telephone: (202) 482–5953.

SUPPLEMENTARY INFORMATION: Although the Export Administration Act (EAA) expired on September 30, 1990, the President, invoking the International Emergency Economic Powers Act, continued in effect the powers of the EAA and the Export Administration Regulations (EAR), to the extent permitted by law, in the Executive Order 12730 of September 30, 1990.

Part 791 of the EAR (15 CFR 730 *et seq.*) establishes the procedures and criteria for determining the foreign availability of goods and technology whose export is controlled and controlled destinations. This equipment is controlled for national security reasons.

On December 7, 1992, OFA initiated a foreign availability assessment pursuant to § 791.4 of the EAR relating to the decontrol of advanced high speed modems using the "bandwidth of one voice channel" with a "data signalling rate" exceeding the current control parameter of 9,600 bits per second to both noncontrolled for national security reasons under paragraph (c)(1) Export Control Classification Number (ECCN) 5A02A of the Commerce Control List (CCL) (15 CFR 799.1, Supp. 1): "Telecommunications transmission equipment".

By May 7, 1993, the Department intends to submit for publication in the **Federal Register** its determination of the foreign availability of the item.

To assist OFA in assessing such foreign availability, any person may submit relevant information to OFA at the above address.

The following information would be especially useful:

—Product names and model designations of the U.S. and non-U.S. items;
—Names and locations of non-U.S. sources;
—Key performance elements, attributes, and characteristics of the items on which quality comparisons may be made;
—Non-U.S. sources' production quantities and/or sales of any allegedly comparable item;
—An estimate of market demand and the potential economic impact of the control on the U.S. item;
—Extent to which any allegedly comparable item is based on U.S. technology;
—Product names, model designations, and value of U.S. controlled parts and components incorporated in any allegedly comparable item; and
—Information supporting the proposition that the foreign item is in fact available to the country or countries for which foreign availability is alleged.

Evidence supporting such relevant information may include, but is not limited to: Foreign manufacturers' catalogs, brochures, or operations or maintenance manuals; articles from reputable trade publications; photographs; and depositions based upon eyewitness accounts. Supplement No. 1 to Part 791 of the EAR provides additional examples of evidence that would be helpful to the investigation.

OFA will also accept comments or information accompanied by a request that part or all of the material be treated confidentially because of its proprietary nature or for any other reason. The information for which confidential treatment is requested should be submitted to OFA separately from any non-confidential information. The top of each page should be marked with the term "Confidential Information." Confidential submissions must include a statement from the submitter that the material is commercial or financial information which the submitter does not customarily release to the public. If OFA will not accept the submission in confidence, it will return it. A non-confidential summary must accompany any submission of confidential information. OFA will make the summary available for public inspection.

Regardless of whether the submitter has requested confidential treatment, OFA will maintain the confidentiality of any information exempt from disclosure under the Freedom of Information Act (5 U.S.C. 552). This may include communications from agencies of the United States Government and foreign governments which are exempt from disclosure under the Freedom of Information Act.

All other information received in response to this notice will be a matter of public record and will be available for public inspection and copying. In the interest of accuracy and completeness, the Department requires written comments. Oral comments must be followed by written memoranda, which also will be a matter of public

record and will be available for public review and copying.

The public record of information received in response to this notice will be maintained in the Bureau of Export Administration's Freedom of Information Records Inspection Facility, room 4525, Department of Commerce, 14th Street and Pennsylvania Avenue NW., Washington, DC 20230. Records in this facility, including written public comments and memoranda summarizing the substance of oral communications, may be inspected and copied in accordance with regulations published in part 4 of title 15 of the Code of Federal Regulations.

Information about the inspection and copying of records at the facility may be obtained from Margaret Cornejo, Bureau of Export Administration, Freedom of Information Officer, at the above address or by calling (202) 482–5653.

Due to the strict statutory time limitations in which Commerce must make its determination, the period for submission of relevant information will close on February 10, 1993. The Department will consider all information received before the close of the comment period in developing the assessment. Information received after the end of the period will be considered if possible, but its consideration cannot be assured.

Accordingly, the Department encourages persons who wish to provide information related to this foreign availability submission to do so at the earliest possible time to permit the Department the fullest consideration of the information.

Dated: January 5, 1993.

James M. LeMunyon,

Acting Assistant Secretary for Export Administration.

[FR Doc. 93–468 Filed 1–8–93; 8:45 am]

BILLING CODE 3510–DT–M

Foreign-Trade Zones Board

[Order No. 624]

Approval for Processing Activity (Auto Audio Components) Within Foreign-Trade Zone 64; Jacksonville, FL

Pursuant to its authority under the Foreign-Trade Zones Act of June 18, 1934, as amended (19 U.S.C. 81a–81u) (the Act), and the Foreign-Trade Zones (FTZ) Board Regulations (15 CFR part 400), the Foreign-Trade Zones Board (the Board) adopts the following order:

Whereas, § 400.28(a)(2) of the Board's regulations, requires approval of the Board prior to commencement of new manufacturing/processing activity within existing zone facilities;

Whereas, Trade Zone Operations, Inc., operator of FTZ 64, Jacksonville, Florida, has requested authority under § 400.32(b)(1) of the Board's regulations on behalf of General Motors Corporation, Chevrolet Motor Division, to use zone procedures for the installation of foreign auto audio components into automobiles assembled abroad for GM (filed 10/29/92, A(32b1)–6–92; Doc. 39–92, assigned 12/22/92);

Whereas, Pursuant to § 400.32(b)(1), the Commerce Department's Assistant Secretary for Import Administration has authority to act for the Board in making such decisions on new manufacturing/processing activity under certain circumstances, including situations where the proposed activity is the same in terms of products involved, to activity recently approved by the Board under similar circumstances (§ 400.32(b)(1)(i)); and,

Whereas, the FTZ Staff has reviewed the proposal, taking into account the criteria of § 400.31, and the Executive Secretary has recommended approval;

Now, therefore, the Assistant Secretary for Import Administration, Acting for the Board pursuant to § 400.32(b)(1), concurs in the recommendation and hereby approves the request subject to the Act and the Board's Regulations (as revised, 56 FR 50790–50808, 10/8/91), including § 400.28.

Signed at Washington, DC, this 30th day of December, 1992, pursuant to Order of the Board.

Alan M. Dunn,

Assistant Secretary of Commerce for Import Administration, Chairman, Committee of Alternates, Foreign-Trade Zones Board.

Attest:

John J. Da Ponte, Jr.,

Executive Secretary.

[FR Doc. 93–544 Filed 1–8–93; 8:45 am]

BILLING CODE 3510–DS–M

[Docket A(28a3)–2–92]

Foreign-Trade Subzone 29C, General Electric Company, Louisville, KY; Compressors for Refrigerators and Room Air Conditioners

The Foreign-Trade Zones Board (the Board) has been notified pursuant to § 400.28(a)(3) of the Board's regulations by the General Electric Company (GE), operator of Foreign-Trade Subzone 29C, Louisville, Kentucky, with additional information as to the use of zone procedures for foreign-sourced compressors used in the manufacture of refrigerators and room air conditioners at the GE home appliance manufacturing plant in Louisville, Kentucky.

The Board authorized subzone status for the GE plant in December 1985 (Board Order 321, 50 FR 52180, 12/27/85). Manufacturing authority involves the production of large home appliances including refrigerators, dishwashers, dryers, electric ranges, and room air conditioners for the U.S. market and for export using certain materials and components sourced from abroad.

The original application listed certain components sourced from abroad to be admitted to the subzone in foreign status. While compressors are among the items sourced abroad, they were now included in that list. GE has not notified the Board that it wishes to admit the compressors (HTSUS #8414.30, duty rate: 3.4%) sourced abroad into the subzone in foreign status. The manufacturing activity otherwise remains unchanged.

Zone procedures would exempt GE from Customs duty payments on the foreign components used in production for export. On domestic sales, the firm would be able to choose the duty rate for finished refrigerators and air conditioners (2.9% and 2.2%) to apply to the foreign-origin compressors (duty rate 3.4%).

Public comment is invited from interested parties. Submissions (original and 3 copies) shall be addressed to the Board's Executive Secretary at the address below. The closing period for their receipt is February 10, 1993. A copy of the request will be available for public inspection at the following location: Office of the Executive Secretary, Foreign-Trade Zones Board, U.S. Department of Commerce, room 3716, 14th Street and Pennsylvania Avenue, NW., Washington, DC 20230.

Dated: December 31, 1992.

John J. Da Ponte, Jr.,

Executive Secretary.

[FR Doc. 93–547 Filed 1–8–93; 8:45 am]

BILLING CODE 3510–DS–M

[Docket No. 38–92]

Foreign-Trade Zone 84; Harris County, TX; Application for Expansion (Houston Port of Entry), Zone Site #11—Oiltanking of Houston, Inc., Houston, TX

An application has been submitted to the Foreign-Trade Zones Board (the Board) by the Port of Houston Authority, grantee of FTZ 84, requesting authority to expand Zone Site 11 at the liquid bulk storage facilities of Oiltanking of Houston, Inc. (Oiltanking) (formerly Oiltanking of Texas, Inc.)

located in Houston, Texas. The application was submitted pursuant to the provisions of the Foreign-Trade Zones Act, as amended (19 U.S.C. 81a–81u), and the regulations of the Board (15 CFR part 400). It was formally filed on December 22, 1992.

The FTZ Board approved FTZ 84 in 1983 (Board Order 214, 48 FR 34792, 8/1/83), and the zone project currently includes 12 sites in Harris County, Texas. Zone Site 11 (50 acres) covers a portion of the Oiltanking facility. It was authorized by the Board for the storage of liquid bulk products in 1988 (Board Order 409, 53 FR 53042, 12/30/88). The facility is located at 15602 Jacintoport Blvd. in Houston, Texas.

The application requests authority to expand Site 11 to cover the entire Oiltanking facility (269 Acres). The expansion would include new storage facilities constructed since 1988, adding 6 million barrels of liquid bulk storage capacity to the 3.1 million barrels at existing site 11. All limitations (e.g., no blending, processing) stated in Board Order 409 authorizing the original site would apply to the expanded site.

In accordance with the Board's regulations, a member of the FTZ Staff has been designated examiner to investigate the application and report to the Board.

Public comment is invited from interested parties. Submissions (original and 3 copies) shall be addressed to the Board's Executive Secretary at the address below. The closing period for their receipt is March 12, 1993. Rebuttal comments in response to material submitted during the subsequent 15-day period is March 29, 1993.

A copy of the application will be available for public inspection at each of the following locations:

U.S. Department of Commerce District Office, #1 Allen Center, 500 Dallas, Suite #1160, Houston, Texas 77002.

Office of the Executive Secretary, Foreign-Trade Zones Board, U.S. Department of Commerce, Room 3716, 14th & Constitution Avenue, NW., Washington, DC 20230.

Dated: December 30, 1992.

John J. Da Ponte, Jr.,

Executive Secretary.

[FR Doc. 93–546 Filed 1–8–93; 8:45 am]

BILLING CODE 3510-DS-M

[Order No. 620]

Expansion of Foreign-Trade Zone 94 Laredo, TX

Pursuant to its authority under the Foreign-Trade Zones (FTZ) Act of June 18, 1934, as amended (19 U.S.C. 81a–81u) (the Act), and the FTZ Board Regulations (15 CFR part 400), the FTZ Board (the Board) adopts the following Resolution and Order:

Whereas, an application from the City of Laredo, Texas, grantee of Foreign-Trade Zone No. 94, for authority (subject to an activation limit) to expand its general-purpose zone to include a site at the International Commerce Center in Laredo, Texas, within the Laredo Customs port of entry, was filed by the Board on November 6, 1991, and notice inviting public comment was given in the **Federal Register** on December 2, 1991 (Docket 77–91, 56 FR 61228);

Whereas, an examiners committee has investigated the application in accordance with the Board's regulations and recommends approval;

Whereas, the expansion is necessary to improve and expand zone services in the Laredo area; and,

Whereas, The Board has found that the requirements of the Act and the Board's regulations are satisfied, and that approval, subject to an activation limit, is in the public interest;

Now, Therefore, the Board hereby orders: That the grantee is authorized to expand its zone in accordance with the application filed on November 6, 1991, subject to the Act and the Board's regulations (as revised, 56 FR 50790–50808, 10–8–91) including § 400.28, and subject to the condition that further Board approval is required prior to activation at the International Commerce Center site beyond 1,500 acres.

Signed at Washington, DC, this 29th day of December, 1992.

Alan M. Dunn,

Assistant Secretary of Commerce for Import Administration, Chairman, Committee of Alternates Foreign-Trade Zones Board.

Attest:

John J. Da Ponte, Jr.,

Executive Secretary.

[FR Doc. 93–545 Filed 1–8–93; 8:45 am]

BILLING CODE 3510-DS-M

International Trade Administration

[A–351–813]

Preliminary Determination of Sales at Less Than Fair Value: Certain Alloy and Carbon Hot-Rolled Bars, Rods, and Semifinished Products of Special Bar Quality Engineered Steel From Brazil

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

EFFECTIVE DATE: January 11, 1993.

FOR FURTHER INFORMATION CONTACT: Cherrie L. Rusnak or Linda L. Pasden, Office of Agreements Compliance, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington, DC 20230; telephone: (202) 482–3793.

PRELIMINARY DETERMINATION: We preliminarily determine that certain alloy and carbon hot-rolled bars, rods, and semifinished products of special bar quality engineered steel from Brazil are being, or are likely to be, sold in the United States at less than fair value, as provided in section 733 of the Tariff Act of 1930, as amended (the Act). The estimated margins are shown in the "Suspension of Liquidation" section of this notice.

Case History

Since the initiation of this investigation on June 29, 1992 (57 FR 29703, July 6, 1992), the following events have occurred.

On July 24, 1992, the U.S. International Trade Commission (ITC) issued an affirmative preliminary injury determination.

On August 14, 1992, the Department presented questionnaires to Industries Villares, S.A. and its related companies (Villares) with regard to finished bars and rods, and to Aco Minas Gerais S.A. (ACOMINAS) with regard to semifinished products. These companies accounted for the overwhelming majority of imports of the subject merchandise from Brazil during the period of investigation. Responses to the questionnaires were originally due on August 27, 1992 and September 14, 1992. At Villares' request, the Department granted extensions until September 3, 1992 for section A and September 28, 1992 for sections B and C of its response. At the request of ACOMINAS, the Department granted extensions until September 1, 1992 for section A and September 28, 1992 for sections B and C of its response. Villares and ACOMINAS submitted their questionnaire responses on the deadlines specified.

On September 21, 1992 and September 22, 1992, petitioners provided comments on the section A responses of ACOMINAS and Villares, respectively. Petitioners requested, on October 6, 1992, a postponement of the preliminary determination from November 16, 1992 until January 5, 1993. The postponement was granted on October 15, 1992 (57 FR 48356, October 23, 1992). On October 7, 1992, petitioners alleged that ACOMINAS and Villares sold the subject merchandise in the home market below its cost of

production (COP). Petitioners submitted comments on the sections B and C responses of both ACOMINAS and Villares on October 15, 1992. Additional comments were provided by petitioners on October 19, 1992 regarding ACOMINAS' sections B and C responses. We issued a supplemental questionnaire and the constructed value questionnaire to ACOMINAS on October 22, 1992. Villares was issued a supplemental questionnaire and a constructed value questionnaire on October 23, 1992. The supplemental questionnaire responses were received from ACOMINAS and Villares on November 5, 1992 and November 13, 1992, respectively.

On October 30, 1992, a COP questionnaire was presented to Villares. ACOMINAS, on November 9, 1992, requested an extension of time to respond to the constructed value questionnaire until December 4, 1992. The Department issued revised model match instructions on November 13, 1992, concerning changes in the methodology used by the Department to compensate for the effects of hyperinflation. Also on November 13, 1992, Villares requested an extension until December 7, 1992, for submission of the revised product concordance, U.S. sales listing, and constructed value/COP information. On November 17, 1992, the Department granted both ACOMINAS' and Villares' requests for extension and issued a second supplemental questionnaire to ACOMINAS.

A COP questionnaire was presented to ACOMINAS on November 18, 1992, which was due and received on December 18, 1992. Also on November 18, 1992, ACOMINAS requested an extension for submission of the second supplemental questionnaire response until November 24, 1992, and requested an additional extension of time until December 4, 1992, to prepare the constructed value response and to prepare a new product concordance in accordance with the Department's November 13, 1992 revised model match instructions. The Department granted this request on November 20, 1992.

On December 2, 1992, the Department met with counsel for ACOMINAS to allow them to explain several discrepancies the Department found in the home market sales, U.S. sales, and differences-in-merchandise databases submitted on November 25, 1992. During this meeting, counsel stated that the product concordance, which was due to the Department on December 4, 1992, had not been done in accordance with the Department's November 13, 1992 revised model match instructions. They stated that ACOMINAS would be revising the concordance and submitting a new one along with the cost of production data on December 18, 1992. However, a request for extension was never received from ACOMINAS regarding the product concordance. Upon receipt of the December 4, 1992 submission, the Department confirmed that the product concordance was not completed in accordance with the instructions issued on November 13, 1992.

On December 2, 1992, the Department issued a second deficiency letter to Villares. The response was due, and was subsequently received, on December 7, 1992. On December 3, 1992, ACOMINAS submitted revised total home market sales volume and value information. Petitioners filed comments regarding legal and factual issues pertinent to the Department's preliminary determination on December 7, 1992.

On December 15, 1992, Villares submitted comments on the Department's change in its methodology concerning difference in merchandise adjustments for price-to-price comparisons. On December 16, 1992, Villares submitted revisions to its U.S. sales listing and cost of production information. Villares submitted further revisions on December 18, 1992 to both the cost of production and constructed value databases. On December 22, 1992, Villares again submitted revised calculations to both the cost of production and the constructed value databases, along with printouts and a revised computer tape.

On December 18, 1992, petitioners submitted comments regarding the constructed value responses filed by ACOMINAS and Villares on December 4, and December 7, 1992, respectively. On this same date, ACOMINAS submitted its cost of production response along with a revised product concordance. ACOMINAS filed, on December 22, 1992, a list of corrections to its December 4, 1992 constructed value information, and to the December 18, 1992 cost of production and product concordance.

Scope of Investigation

The products covered in this investigation are:

- Hot-finished alloy and carbon bars and rods of special bar quality engineered steel.
- Semifinished products of special bar quality engineered steel.

The term "hot-finished alloy and carbon bars and rods of special bar quality engineered steel" covers certain hot-finished carbon and alloy steel (other than stainless steel, high-speed steel, silico-manganese steel, and tool steel) bars and rods, other than forged, which have a uniform solid cross-section along their whole length and are in the shape of circles, segments of circles, ovals, rectangles, triangles, or other convex polygons, and do not conform to the definitions for semifinished steel, flat-rolled products, hot-rolled bars and rods in irregularly wound coils, reinforcing bars and rods, and wire. The subject bars and rods are of special bar quality engineered steel that is described in Society of Automotive Engineers (SAE) J403, J404, J411, J1081, J1249, J1268, and modifications thereof, whether they be domestic or foreign, of other than merchant quality grades M 1000 through M 1044, not containing by weight 0.03 percent or more of lead or 0.05 percent or more of bismuth, as classifiable under the following subheadings of the Harmonized Tariff Schedule of the United States (HTS): 7214.30.0000, 7214.40.0010, 7214.40.0030, 7214.40.0050, 7214.50.0010, 7214.50.0030, 7214.50.0050, 7214.60.0010, 7214.60.0030, 7214.60.0050, 7228.30.8005, and 7228.30.8050.

The term "semifinished products of special bar quality engineered steel" covers certain alloy steel ingots (other than stainless steel, high-speed steel, silico-manganese steel, tool steel, and high-nickel alloy steel), and semifinished products of carbon and alloy steel (other than stainless steel, high-speed steel, silico-manganese steel, tool steel, and high-nickel alloy steel) of circular or rectangular (including square) cross-section with a width measuring less than four times the thickness, of special bar quality engineered steel that is described in Society of Automotive Engineers (SAE) J403, J404, J411, J1081, J1249, J1268, and modifications thereof, whether they be domestic or foreign, not containing by weight 0.03 percent or more of lead or 0.05 percent or more of bismuth, as classifiable under the following subheadings of the Harmonized Tariff Schedule of the United States (HTS): 7207.11.0000, 7207.12.0010, 7207.19.0030, 7207.20.0025, 7207.20.0075, 7224.10.0075, 7224.90.0045, and 7224.90.0065.

Although the HTS subheadings are provided for convenience and customs purposes, our written description of the scope of this proceeding is dispositive.

Class or Kind of Merchandise

When the Department initiated this investigation on June 29, 1992 (57 FR

29703), we provisionally accepted petitioners' claim that the subject merchandise comprised one class or kind. However, we also noted our reservations regarding petitioners' claim, and allowed for a 14-day period during which interested parties were requested to comment on the scope of this proceeding. The Department summarized its concerns regarding the class or kind issue in more detail in a memorandum to the file dated July 17, 1992.

During the comment period, the Department received comments from petitioners and respondents and from one importer of the subject merchandise. Department staff also toured petitioners' steelmaking facilities on July 28, 1992, to gain more detailed knowledge about the production process and channels of trade of the subject merchandise.

In considering whether the merchandise subject to investigation comprised one or several classes or kinds of merchandise, the Department applied the criteria used to evaluate class or kind of merchandise established in *Diversified Products* versus *United States*, 6 CIT 155 (1983), and incorporated into our examination an analysis of the comments received and of the information collected during the steel plant tours. Based on our examination, we determined in a decision memorandum of August 12, 1992, that the subject merchandise of this investigation constitutes two distinct classes or kinds: Alloy and carbon hot-rolled bars and rods of special bar quality engineered steel, and semifinished products of special bar quality engineered steel.

In our August 12 decision memorandum, we noted that there are distinct differences in physical characteristics between semifinished products and hot-rolled bars and rods of special bar quality engineered steel. We explained that semifinished products have a larger grain structure, a rough appearance, and relatively inexact tolerances, while hot-rolled bars and rods have smaller grains and a much smoother surface condition with few or no surface imperfections, and tolerances that are significantly more exacting than those for semifinished products. We also noted that semifinished products and hot-rolled bars and rods of special bar quality engineered steel have different ultimate uses, in that semifinished products are usually further hot-rolled by steel companies (although they are forged in a minority of instances), while hot-rolled bars and rods have numerous ultimate uses, including machining, forging, and hot- and cold-forming. We concluded that the expectations of the ultimate purchasers of semifinished products and hot-rolled bars and rods of special bar quality engineered steel are different. Specifically, consumers of hot-rolled bars and rods expect a product which meets relatively exacting tolerances, while consumers of semifinished products do not require such exacting specifications. We observed that semifinished products and hot-rolled bars and rods of special bar quality engineered steel have different channels of trade, as most semifinished products are consumed internally by steelmakers and generally cannot be used by outside customers, while hot-rolled bars and rods are normally sold to outside customers who perform various operations on the product. Finally, we noted that semifinished products and hot-rolled bars and rods of special bar quality engineered steel are advertised differently, as semifinished products are not generally sold to outside customers and therefore are not generally advertised, while hot-rolled bars and rods generally are sold and advertised to producers of end-user products.

Period of Investigation

The period of investigation (POI) is January 1, 1992 through June 30, 1992.

Use of Best Information Available

ACOMINAS

As stated above, the product concordance submitted by ACOMINAS on December 4, 1992 was not done in accordance with the Department's revised model match instructions issued on November 13, 1992. A request for extension to revise and resubmit this information was never received from ACOMINAS. However, this respondent did in fact file a revised product concordance on December 18, 1992 and, on December 22, 1992, submitted corrections to be made to the concordance.

In its December 23, 1992 submission, ACOMINAS argued that the Department should use home market prices or constructed value as the basis for foreign market value in its preliminary determination. Respondent further argued that the Department had sufficient time to incorporate the December 18, 1992 cost of production data into its preliminary determination. However, no mention was made of the new product concordance which was also submitted on December 18, 1992.

ACOMINAS is incorrect in its claim that the Department had sufficient time to use the information submitted on December 18, 1992 in making its preliminary determination. Because respondent did not submit a complete and accurate response in a timely manner, the Department was, in fact, unable to perform a complete and accurate analysis of ACOMINAS' selling practices in time for its preliminary determination. The best information rule prevents a respondent from controlling the results of the investigation by providing partial information or by delaying or otherwise hindering the investigation. The Department is not required to use selected portions of an incomplete response, and is thus justified in relying on information supplied by petitioners as the "best information otherwise available." *Pistachio Group of the Ass'n of Food Indus.* v. *United States*, 11 CIT 668, 679, 671 F. Supp. 31, 40 (1987).

However, because ACOMINAS has submitted a revised product concordance on the record which will be reviewed for possible consideration for use in the final determination, and has been cooperative throughout this proceeding, we used the average margin (of the 1992 sales) alleged in the petition for semifinished products, which is 19.67%, as best information available for the preliminary determination.

Villares

The Department reviewed the cost of production and constructed value information submitted by Villares on December 7, 1992 and found several fundamental flaws which the Department was unable to correct.

For example, Villares' submitted material costs, which are a significant component of the cost of manufacture for special bar quality engineered steel, were based on standard yield rates, i.e., the theoretical quantity of consumption of each type of material for each stage of production, instead of actual usage. In addition, respondent computed average acquisition "at sight" prices for each raw material type by reducing the gross unit price recorded on invoices by an imputed financing amount, claiming that the gross unit prices are inclusive of financing charges for extended payment terms. However, no documentation was submitted to support this claim, and it does not appear that Villares' normal accounting system adjusts for payment terms. In addition, adjusting for payment terms appears to double count the benefit received from delayed payment since the Department already reduces COP and constructed value by short term interest income (see Memorandum to Marie E. Parker, Office of Accounting, dated December 28, 1992). The

computer tapes submitted by Villares reflected only the "at sight" figures, and not the gross unit prices. Therefore, the Department was itself unable to revise the computer program to reflect gross unit input prices.

Because all of the pertinent information was not provided on the computer tapes (i.e., the gross prices for raw material inputs), because certain requested data were not provided at all (i.e., actual yields), and because there were various incorrect calculations, the Department determined that this information could not be used to reflect accurately the production costs for the POI. See *Rhone Poulenc, Inc.* v. *United States*, 13 CIT 218, 710 F.Supp. 341, (1989). Therefore, in accordance with section 353.37(a)(1) of the Department's regulations, we have resorted to the best information available for the preliminary determination.

However, because a deficiency letter has not yet been issued regarding the COP and constructed value data and, like ACOMINAS, Villares has been cooperative throughout this proceeding, we used the average margin (of the 1992 sales) alleged in the petition for finished bars and rods, which was 57.00%, as the best information available for the preliminary determination (see § 353.37(b)).

Verification

As provided in section 776(b) of the Act, we will verify the information used in making our final determination.

Suspension of Liquidation

In accordance with section 733(d)(1) of the Act, we are directing the Customs Service to suspend liquidation of all entries of certain alloy and carbon hot-rolled bars, rods, and semifinished products of special quality engineered steel from Brazil that are entered, or withdrawn from warehouse, for consumption on or after the date of publication of this notice in the **Federal Register**. The Customs Service shall require a cash deposit or posting of a bond equal to the estimated preliminary dumping margins, as shown below. This suspension of liquidation will remain in effect until further notice. The average dumping margins are as follows:

Producer/manufacturer/exporter	Weighted-average margin percentage
Semifinished products	
Aco Minas Gerais S.A.	19.67
All others	19.67
Finished bars and rods	
Industrias Villares S.A. and its related companies	57.00
All others	57.00

ITC Notification

In accordance with section 733(f) of the Act, we have notified the ITC of our determination. If our final determination is affirmative, the ITC will determine before the later of 120 days after the date of this preliminary determination or 45 days after our final determination whether these imports are materially injuring, or threatening material injury to, the U.S. industry.

Public Comment

In accordance with 19 CFR 353.38, case briefs or other written comments, in at least ten copies, must be submitted to the Assistant Secretary for Import Administration no later than March 3, 1993. Rebuttal briefs must be submitted no later than March 8, 1993. In accordance with 19 CFR 353.38(b), we will hold a public hearing, if requested, to afford interested parties an opportunity to comment on arguments raised in case or rebuttal briefs. Tentatively, the hearing will be held on March 10, 1993, at the U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington, DC 20230. Parties should confirm by telephone the time, date, and place of the hearing 48 hours before the scheduled date.

Interested parties who wish to request a hearing, or to participate if one is requested, must submit a written request to the Assistant Secretary for Import Administration, U.S. Department of Commerce, room B–099, within ten days of the publication of this notice. Requests should contain: (1) The party's name, address, and telephone number; (2) the number of participants; and (3) a list of issues to be discussed. In accordance with 19 CFR 353.38(b), oral presentations will be limited to issues raised in the briefs.

This determination is published pursuant to section 733(f) of the Act and 19 CFR 353.15(a)(4).

Dated: January 5, 1992.

Alan M. Dunn,

Assistant Secretary for Import Administration.

[FR Doc. 93–542 Filed 1–8–93; 8:45 am]

BILLING CODE 3510–DS–M

Special Export Permit Determination: Certain Machining Center Frames and Machining Centers

AGENCY: Import Administration/ International Trade Administration, Commerce.

ACTION: Notice of determination denying authorization of special export permits for certain machining center frames and machining centers.

SUMMARY: The Department of Commerce ("Department") hereby denies a request for special export permits for 400–450 machining center frames for 1992 and 1993, and 50 machining centers for July–December 1992, under Paragraph 9 of the Understanding Between the Coordination Council for North American Affairs and the American Institute in Taiwan Concerning Trade in Certain Machine Tools.

FOR FURTHER INFORMATION CONTACT: Joseph A. Spetrini, Import Administration, U.S. Department of Commerce, room 3069A, 14th Street & Constitution Avenue, NW., Washington, DC 20230 (202) 482–2104.

SUPPLEMENTARY INFORMATION: Pargraph 9 of the Understanding Between the Coordination Council for North American Affairs (CCNAA) and the American Institute in Taiwan (AIT) Concerning Trade in Certain Machine Tools (Understanding) provides for the authorization of special export permits. Such permits allow the importation of machine tools from the territory represented by CCNAA to the territory represented by AIT in excess of the applicable export limit provided for in the Understanding when we determine that: (a) Approval would serve a unique national security need; (b) approval would directly lead to an increase in U.S. machine tool manufacturing capacity; and/or (c) comparable tools are not available from U.S. manufacturers or suppliers. Special export permits are authorized for a limited time period and for a specified number of machines, on a product-by-product basis.

On June 26, 1992, Hurco Companies, Inc. (Hurco) submitted a special export permit authorization request for 400–450 cast iron frames for machining centers for 1992 and 1993, and 50 machining centers without numerical controls for July–December 1992 under Paragraph 9 of the Understanding. The requested products are considered to be substantially complete machine tools subject to the quantitative export limits of the Understanding.

On July 2, 1992, the Department published a notice which announced Hurco's request in the **Federal Register** and provided an opportunity for public comments (57 FR 29628). Initial comments were to be submitted no later than July 6, 1992, with replies to those comments due no later than July 10, 1992. A public record of these comments is on file in the Central Records Unit, room B–099, Import Administration, U.S. Department of Commerce, at the above address.

The Department received a total of 35 comments to the **Federal Register** notice. Included in these comments were three submissions (Met-Coil Systems Corporation, The National Acme Company, and Deputy Assistant Secretary of Defense David Berteau) supporting Hurco's request, and rebuttal comments by Hurco. The two companies that supported Hurco's request did not address the criteria specifically, but rather submitted brief, general statements of support. The remaining 31 comments objected to Hurco's request.

Analysis

The Department analyzed Hurco's request, and the comments received, in the context of the criteria for authorizing special export permits outlined above. Each criterion is addressed below.

Unique National Security Need

In its request, Hurco notes that it is a "leader in research and development of critical computer numerical control and software technology" and that special permits are needed to save highly skilled employment, production capability, and ensure continued development of essential technology. David Berteau, Principal Deputy Assistant Secretary of Defense, writes in a letter that "Hurco is a leader in open architecture control and software technology and has extensively participated in the National Center for Manufacturing Sciences (NCMS) sponsorship of the development of this technology. The Department believes such (favorable) consideration will enhance, rather than impair, the domestic machine tool industrial base, with commensurate benefits for national security."

Most comments received, however, question whether Hurco's contribution with regard to controls and software is in fact unique and whether it serves a unique national security need. Several parties note that the open architecture concept is not new or unique to any one supplier. Three companies (Bridgeport Machines, Anilam Electronics Corporation, and Fadal Engineering Co. Inc.) stated that they have introduced PC-based open architecture control systems. They also note that other U.S. companies (e.g., Thermwood Corporation and Automation Intelligence) also manufacture PC-based open architecture machine tool controls. Cincinnati Milacron and Giddings & Lewis claim to have added open architecture features to their own control systems. Giddings & Lewis further notes that Hurco "controls and software technology are not used on the advanced CNC machine tools and flexible manufacturing systems used to manufacture today's advanced weapon systems. Over the years, Giddings & Lewis has been and will continue to be a leading supplier of advanced controls and software technology needed to make sophisticated weapon systems." Giddings & Lewis also noted that several firms other than Hurco (including Giddings & Lewis, Allen-Bradley, Cincinnati Milacron and Automation Intelligence) have also been participating in the Next Generation Control project sponsored by NCMS.

Although Hurco states its position as that of a leader in research and development of critical computer numerical control and software technology, no evidence was provided by any party that Hurco has made a unique contribution to machine tool control and/or software development. Hence, we have no basis to believe that Hurco's control is more open or more technologically advanced than other systems produced domestically.

As a result, the Department determines that this criterion has not been met. Information on the record indicates that several U.S. companies have made significant advances in both PC-based and other forms of open architecture control and software technology and are producing machine tool computer numerical controls (CNC) using this technology, and no other information on the record demonstrates that authorizing Hurco's request would serve a unique national security need.

Increase in U.S. Machine Tool Manufacturing Capacity

Hurco states that it has requested special export permits to maintain its domestic supply base of over 1,600 U.S. suppliers and purchases of over $3 million. Approval of this request, Hurco argues, would allow it to "maintain viable manufacturing operations in the United States and continue the important research and development in critical CNC and software technology." Hurco argues that the effect of cast iron imports on the domestic industry would be minimal.

Various parties state that granting this request will have a negative effect on U.S. machine tool manufacturing capacity. The Association of Manufacturing Technology (AMT) notes that granting this request would result in "decreased (domestic) manufacturing capacity." Several domestic machine tool producers claim that granting this request would result in their losing market share to Hurco. Haas Automation Inc. states "an open exception to the Hurco Companies will allow them to flood the market with cheap iron from Taiwan harming the companies who actually build equipment in the USA." Fadal writes that "granting this request will do nothing for national security and will have a negative effect on U.S. machine tool manufacturing capacity * * * Hurco has targeted Fadal" and "the impact of your granting this request will be born[e] primarily by Fadal. We sincerely doubt that Hurco's imported machine tools will displace many other imports." Bridgeport indicates that if this request is approved, "Bridgeport Machines would find itself in the unfortunate position of losing market share [to Hurco]." Another company states that "Hurco cannot contend that these licenses will ultimately expand U.S. manufacturing capacity * * * Even in their own statement, Hurco claims to be an 'assembler' of machine tools. 'Assembly' is not, of course, manufacturing."

Haas argues that approval of Hurco's request would adversely affect the U.S. machine tool supplier base. "If our company is harmed, so to[o] will all of our suppliers including the foundries who provide us with our American made parts." Cast-Fab Technologies, Inc., a major U.S. foundry, notes that granting Hurco's request would undermine the investments and quality improvements made by U.S. machine tool suppliers.

In discussing the impact approval would have on U.S. capacity, Hurco argues that some other domestic firms import complete machining centers. However, Hurco overstates the extent to which this practice is occurring. Hurco fails to mention that Fadal and Haas—two of Hurco's major domestic competitors—produce machining centers and controls exclusively in the United States. One company cited by Hurco imports only one model from an overseas subsidiary, producing all other machining center models and controls in the United States. In any event, these imports are from non-VRA countries and thus are not relevant to a determination under the Understanding.

Mr. Berteau of the Department of Defense suggests that favorable consideration of Hurco's current request would be similar to that received by Hurco prior to 1991 under the original machine tool agreement with CCNAA. However, the original VRA negotiated with CCNAA in 1986 contained a transitional provision to facilitate transfer of input sourcing and machine tool manufacturing from Taiwan to the United States and non-VRA countries, which the current Understanding does not contain. We note that after an

extended transition period toward domestic sourcing, Hurco advised the Department that this process would be complete in 1991. On March 25, 1991, Hurco wrote to the Department as follows: "We ask the Department to assist Hurco Companies in completing its transition to domestic sourcing and machining of certain castings for machining centers by authorizing the Taiwan authorities to issue special licenses for the export to Hurco Companies of 14 substantially complete machining centers * * * These machines are ready for shipment and are intended to tide us over until we receive the [domestic] castings we have ordered. After the export of the 14 substantially complete machining centers under special licenses, Hurco will satisfy the Criteria for Substantially Complete Machining Centers for all subsequent imports from Taiwan of machining center components or obtain regular export licenses." The Department granted this request. Since mid-1991, Hurco has been sourcing and machining certain castings domestically. Approving Hurco's request thus would amount to facilitating a reversal of the changes Hurco made to comply with the machine tool program's overall objectives. Hurco has failed to demonstrate how returning to importing such components from Taiwan would benefit domestic manufacturing capacity.

In summary, there is no evidence on the record to indicate that approval of this request would lead to an increase in U.S. machine tool manufacturing capacity. Hurco is requesting permission to import all major castings from Taiwan, with all machining of these castings performed in Taiwan. Hurco is currently sourcing and machining certain castings in the United States, and assembling them at its Indianapolis facility. Approval would allow Hurco to import substantially complete machining centers, not individual castings, and thus would not lead to increased U.S. machine tool manufacturing capacity. Since the record does not indicate that an increase in machine tool manufacturing capacity would occur if Hurco's request was authorized, this criterion has not been met.

Comparable Tools Are Not Available From U.S. Manufacturers or Suppliers

Hurco does not claim that there is a shortage of machining centers or castings in the United States or that its machines are unique. Rather, Hurco states that it needs a single castings source and that it cannot "mix and match" castings from different foundries since "multiple suppliers of machined cast iron components has deteriorated our ability to compete."

Various parties argue that there is no shortage of the machining centers Hurco sells. One company refers to its low capacity utilization rates. Haas states "there is not a shortage of machine tools in the U.S. at this time. We feel that there is a considerable excess in capacity in our industry." Several parties also note that there is no shortage of high-quality U.S. castings. In fact, Giddings & Lewis offered to supply Hurco with castings from its Wisconsin foundry. The American Foundrymen's Society offered to work with Hurco "to identify foundries that are very capable of supplying their machine bases in a timely manner and at the desired quality level."

While Hurco states that it cannot "mix and match" castings from multiple sources, domestic machine tool builders routinely do just that. Hurco's desire for a single casting source does not form the basis for concluding that the requested products are unavailable from U.S. machine tool manufacturers and suppliers. Satisfying this criterion entails a demonstration that domestic suppliers cannot provide or produce the requested products. There is no information on the record that such a situation exists.

In fact, the preponderance of the information submitted to the Department establishes that the machining centers and castings Hurco wishes to import in excess of the Understanding's limits are available from domestic sources. Therefore, we determine that Hurco has failed to meet the criterion that comparable products are not available from U.S. manufacturers or suppliers.

Conclusion

The Department has determined that authorization of special export permits for Hurco would not serve a unique national security need. While Hurco and Defense claim that Hurco is a leader in open architecture control systems, other U.S. companies produce open architecture PC-based controls. The record does not contain any information indicating that Hurco's control is more open or technologically advanced than those produced by others. Further, Hurco has not indicated how approval of permits would lead directly to an increase in U.S. machine tool manufacturing capacity; in fact, others in the industry claim that approval would work to the detriment of the industry as a whole. Finally, the record demonstrates that there is no shortage of domestic machining centers and that domestic sources are available for the castings Hurco seeks authorization to import from Taiwan.

Because Hurco has not demonstrated that its request for special export permits satisfies the criteria for the authorization of such permits, the Department denies its request in its entirety.

Alan M. Dunn,

Assistant Secretary for Import Administration.

[FR Doc. 93–543 Filed 1–8–93; 8:45 am]

BILLING CODE 3510–DS–M

National Telecommunications and Information Administration

National Endowment for Children's Educational Television, Advisory Council on Children's Educational Television; Open Meeting

AGENCY: National Telecommunications and Information Administration (NTIA), DOC.

ACTION: Notice is hereby given of the second meeting of the Advisory Council on Children's Educational Television, created pursuant to the National Endowment for Children's Educational Television Act of 1990.

SUMMARY: Congress established the National Endowment for Children's Educational Television under the direction of the Secretary of Commerce. Authority to administer this program is further delegated to the National Telecommunications and Information Administration. Congress mandated creation of the Advisory Council to advise on the making of contracts and grants to aid in the creation and production of television programming specifically directed toward the development of fundamental intellectual skills.

AUTHORITY: Public Law 101–437, 104 Stat. 997, approved October 18, 1990, codified at 47 U.S.C. 394.

DATES: The meeting will be held on Wednesday, January 27, 1993, from 10 a.m. to 4:30 p.m.

ADDRESSES: The meeting will take place in room 6800 of the Herbert C. Hoover Commerce Building, 14th Street and Constitution Avenue, NW., Washington, DC 20230.

FOR FURTHER INFORMATION CONTACT: Dr. Heather Birnie; Acting Director, National Endowment for Children's Educational Television (NECET); National Telecommunications and Information Administration (NTIA); U.S. Department of Commerce, room

4625, 14th Street and Constitution Avenue, NW.; Washington, DC 20230. Telephone: 202/482–5802.

SUPPLEMENTARY INFORMATION: The Council was chartered on September 13, 1991 pursuant to 47 U.S.C. 394 to advise the Secretary of Commerce on matters related to the making of contracts and grants that would enhance the education of children through the creation and production of television programming specifically directed toward the development of fundamental intellectual skills.

AGENDA.

1. Opening Introductions and Remarks by participants from the National Telecommunications and Information Administration (NTIA) and the National Endowment for Children's Educational Television (NECET).
2. Discussion of Draft NECET Notice of Availability of Funds, the public announcement of the availability of funding for the creation and production of children's educational television programming.
3. Future Meeting Dates and Agenda Items.
4. Other Items for Discussion.

PUBLIC PARTICIPATION: The meeting will be open to the public, with limited seating available on a first-come, first-served basis.

Gregory F. Chapados,

Assistant Secretary for Communications and Information.

[FR Doc. 93–480 Filed 1–8–93, 8:45 am]

BILLING CODE 3510–60–M

COMMITTEE FOR THE IMPLEMENTATION OF TEXTILE AGREEMENTS

Announcing Settlement on Import Limits and a Guaranteed Access Level for Certain Wool Textile Products Produced or Manufactured in the Dominican Republic

January 5, 1993.

AGENCY: Committee for the Implementation of Textile Agreements (CITA).

ACTION: Issuing a directive to the Commissioner of Customs establishing a limit and announcing a guaranteed access level.

EFFECTIVE DATE: January 12, 1993.

FOR FURTHER INFORMATION CONTACT: Naomi Freeman, International Trade Specialist, Office of Textiles and Apparel, U.S. Department of Commerce, (202) 482–4212. For information on the quota status of this limit, refer to the Quota Status Reports posted on the bulletin boards of each Customs port or call (202) 927–5850. For information on embargoes and quota re-openings, call (202) 482–3715.

SUPPLEMENTARY INFORMATION:

Authority: Executive Order 11651 of March 3, 1972, as amended; section 204 of the Agricultural Act of 1956, as amended (7 U.S.C. 1854).

In a Memorandum of Understanding (MOU) dated December 22, 1992, between the Governments of the United States and the Dominican Republic agreement was reached agreement to establish a limit for wool textile products in Category 443 for the periods September 30, 1992 through January 31, 1993, February 1, 1993 through December 31, 1993, and January 1, 1994 through December 31, 1994.

Also, the two governments agreed to establish a guaranteed access level (GAL) for Category 443 for the periods February 1, 1993 through December 31, 1993, and January 1, 1994 through December 31, 1994.

Beginning on January 15, 1993, the U.S. Customs Service will start signing the first section of the form ITA–370P for shipments of U.S. formed and cut parts in Category 443 that are destined for the Dominican Republic and subject to the GAL established for Category 443 for the period beginning on February 1, 1993 and extending through December 31, 1993. These products are governed by Harmonized Tariff item number 9802.00.8010 and chapter 61 Statistical Note 5 and chapter 62 Statistical Note 3 of the Harmonized Tariff Schedule. Interested parties should be aware that shipments of cut parts in Category 443 must be accompanied by a form ITA–370P, signed by a U.S. Customs officer, prior to export from the United States for assembly in the Dominican Republic in order to qualify for entry under the Special Access Program.

In the letter published below, the Chairman of CITA directs the Commissioner of Customs to establish a limit for Category 443 for the period beginning on September 30, 1992 and extending through January 31, 1993 and to begin signing the first section of form ITA–370P.

A description of the textile and apparel categories in terms of HTS numbers is available in the CORRELATION: Textile and Apparel Categories with the Harmonized Tariff Schedule of the United States (see **Federal Register** notice 56 FR 60101, published on November 27, 1991; and 57 FR 54976, published on November 23, 1992). Also see 57 FR 47328, published on October 15, 1992.

Requirements for participation in the Special Access Program are available in **Federal Register** notices 51 FR 21208, published on June 11, 1986; 52 FR 6594, published on March 4, 1987; 52 FR 26057, published on July 10, 1987; and 54 FR 50425, published on December 6, 1989.

The letter to the Commissioner of Customs and the actions taken pursuant to it are not designed to implement all of the provisions of the MOU, but are designed to assist only in the implementation of certain of its provisions.

J. Hayden Boyd,

Acting Chairman, Committee for the Implementation of Textile Agreements.

Committee for the Implementation of Textile Agreements

January 5, 1993.

Commissioner of Customs,
Department of the Treasury, Washington, DC 20229.

Dear Commissioner: Under the terms of section 204 of the Agricultural Act of 1956, as amended (7 U.S.C. 1854), and the Arrangement Regarding International Trade in Textiles done at Geneva on December 20, 1973, as further extended on July 31, 1991; pursuant to the Memorandum of Understanding (MOU) dated December 22, 1992 between the Governments of the United States and the Dominican Republic; and in accordance with the provisions of Executive Order 11651 of March 3, 1972, as amended, you are directed to prohibit, effective on January 12, 1993, entry into the United States for consumption and withdrawal from warehouse for consumption of wool textile products in Category 443, produced or manufactured in the Dominican Republic and exported during the four-month period beginning on September 30, 1992 and extending through January 31, 1993, in excess of 49,352 numbers [1].

The limit set forth above is subject to adjustment in the future pursuant to the provisions of the MOU dated December 22, 1992 between the Governments of the United States and the Dominican Republic.

For the import period September 30, 1992 through October 31, 1992, you are directed to charge 14,992 numbers to the limit established in this directive for Category 443.

Beginning on January 15, 1993, the U.S. Customs Service is directed to start signing the first section of the form ITA–370P for shipments of U.S. formed and cut parts in Category 443 that are destined for the Dominican Republic and re-exported to the United States on and after February 1, 1993.

In carrying out the above directions, the Commissioner of Customs should construe entry into the United States for consumption to include entry for consumption into the Commonwealth of Puerto Rico.

The Committee for the Implementation of Textile Agreements has determined that these actions fall within the foreign affairs exception of the rulemaking provisions of 5 U.S.C. 553(a)(1).

[1] The limit has not been adjusted to account for any imports exported after September 29, 1992.

Sincerely,

J. Hayden Boyd,

Acting Chairman, Committee for the Implementation of Textile Agreements.

[FR Doc. 93–467 Filed 1–8–93; 8:45 am]

BILLING CODE 3510–DR–F

DEPARTMENT OF DEFENSE

Department of the Army

Board of Visitors, United States Military Academy; Open Meeting

In accordance with section 10(a) (20) of the Federal Advisory Committee Act (Pub. L. 92–463), announcement is made of the following meeting:

Name of Committee: Board of Visitors, United States Military Academy

Date of Meetings: 24 February 1993

Place of Meeting: Washington, DC

Start Time of Meeting: 8 a.m.

Proposed Agenda: Election of officers; selection of Executive Committee; scheduling of meetings for remainder of year; and identification of areas of interest for 1993.

All proceedings are open. For further information contact Lieutenant Colonel Stephen R. Furr, United States Military Academy, West Point, New York 10996–5000, (914) 938–5870.

Kenneth L. Denton,

Army Federal Register Liaison Officer.

[FR Doc. 93–466 Filed 1–8–93; 8:45 am]

BILLING CODE 3710–08–M

Intent To Grant an Exclusive License to Elan Pharmaceutical Research Corp.

AGENCY: Office of the Army Judge Advocate General, DOD.

ACTION: Notice of intent.

In compliance with 37 CFR 404 *et seq.*, the Department of the Army hereby gives notice of its intent to grant to Elan Pharmaceutical Research Corporation, a corporation having its principal place of business at 1300 Gould Drive, Gainesville, GA 30504, an exclusive license under U.S. Patent Application SN 07/779/744, entitled "Composition and Method for Therapy and Prevention of Cancer, AIDS, and Anemia." Anyone wishing to object to the grant of this license has 60 days from the date of this notice to file written objections along with supporting evidence, if any.

EFFECTIVE DATE: This grant of exclusive license becomes effective on the 61st day after the publishing date in the **Federal Register** unless otherwise rescinded or changed.

ADDRESSES: Send or objectives to Intellectual Property Law Division, Office of the Judge Advocate General, ATTN: JALSIP (Earl T. Reichert), 901 North Stuart Street, Arlington, VA 22203–1837.

FOR FURTHER INFORMATION CONTACT: Earl T. Reichert, (703) 696–8113.

Kenneth L. Denton,

Army Federal Register Liaison Office.

[FR Doc. 93–464 Filed 1–8–93; 8:45 am]

BILLING CODE 3710–08–M

Imposition of Secrecy Orders on Patent Applications Under Secrecy Act

AGENCY: Office of the Army Judge Advocate General, DOD.

ACTION: Notice of proposed action.

SUMMARY: Section 181 of title 35 U.S. Code provides that the Commissioner of Patents, upon being notified by an interested agency that the publication of an invention by the grant of a patent on a pending patent application might, or would, be detrimental to the national security, shall order that the invention be kept secret and shall withhold the issuance of a patent for such period as the national interest requires by the issuance of Secrecy Orders.

By Chapter of 28 September 1953, the Secretaries of the Army, Navy and Air Force delegated to the Armed Services Patent Advisory Board (ASPAB), a joint agency of the three military departments, the authority to recommend the imposition of such Security Orders.

In 1985, ASPAB began recommending the imposition of Secrecy Orders on unclassified patent applications which may be export controlled based on the guidelines contained in the Military Critical Technologies List (MCTL).

A report issued by the Advisory Panel on the National Defense Authorition Act in July 1992, and a report issued in August 1992 by the Advisory Commission on Patent Law Reform, have both questioned the practice of using the MCTL to implement unilateral export controls in a manner inconsistent with criteria established for export of technical data by the Departments of State and Commerce.

At a meeting on 26 October 1992 ASPAB adopted the following motion:

Members of ASPAB will discontinue the use of the MCTL or export control regulations as a basis to impose or renew secrecy orders on U.S. patent applications. They will rely primarily on classification guides in determining whether publication or disclosure by the grant of a patent on an invention contained in a U.S. patent application would be detrimental to the national security.

ADDRESSES: Forward written comments within 30 days to: ASPAB, U.S. Army Intellectual Property Law Division, 901 North Stuart Street, suite 400, Arlington, VA 22203–1837.

FOR FURTHER INFORMATION CONTACT: Mr. Earl T. Reichert, (703) 696–8113.

Kenneth L. Denton,

Army Federal Register Liaison Officer.

[FR Doc. 93–465 Filed 1–8–93; 8:45 am]

BILLING CODE 3710–08–M

DEPARTMENT OF EDUCATION

Educational Research Grant Program: Improved Assessments of K–12 Student Performance and State Systemic Educational Reforms

AGENCY: Department of Education.

ACTION: Withdrawal of notices of proposed priorities.

SUMMARY: The Secretary withdraws notices of proposed priorities for Educational Research Grant Program: Improved Assessments of K–12 Student Performance published on August 3, 1992 (57 FR 34170) and Educational Research Grant Program: State Systemic Educational Reforms published on August 11, 1992 (57 FR 35956). The Secretary withdraws these proposed priorities because no funds are available for fiscal year 1993 to support awards under these priorities.

FOR FURTHER INFORMATION CONTACT: Dr. Joseph Conaty, U.S. Department of Education, Office of Educational Research and Development, 555 New Jersey Avenue, NW., room 610, Washington, DC 20208–5573. Telephone: (202) 219–2079. Deaf and hearing impaired individuals may call the Federal Dual Party Relay Service at 1–800–877–8339 (in the Washington, DC 202 area code, telephone 708–9300) between 8 a.m. and 7 p.m., Eastern time.

Dated: December 31, 1992.

Lamar Alexander,

Secretary of Education.

(Catalog of Federal Domestic Assistance Number 84.117, Educational Research Grant Program)

[FR Doc. 93–460 Filed 1–8–93; 8:45 am]

BILLING CODE 4000–01–M

National Assessment Governing Board; Meetings

AGENCY: National Assessment Governing Board; Education.

ACTION: Notice of closed meetings.

SUMMARY: This notice sets forth the schedule and proposed agenda of forthcoming meetings of the Achievement Levels Committee,

Executive Committee, and the full National Assessment Governing Board. This notice also describes the functions of the Board. Notice of these meetings is required under section 10(a)(2) of the Federal Advisory Committee Act.

Date: January 12, January 13, and January 14, 1993.

Time: January 12, 1993—Achievement Levels Committee, noon to 4 p.m. (closed);

January 13, 1993—Executive Committee, 3 p.m. to 4:30 p.m. (closed);

January 14, 1993—Full Board, 1 p.m. to 3 p.m. (closed).

LOCATION: January 12, Phoenix Park Hotel, Washington, DC; January 13 and 14, teleconferences, National Assessment Governing Board, 800 North Capitol Street, NW., Suite 825, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Mary Ann Wilmer, Operations Officer, National Assessment Governing Board, Suite 825, 800 North Capitol Street, NW., Washington, DC, 20002–4233, Telephone: (202) 357–6938.

SUPPLEMENTARY INFORMATION: The National Assessment Governing Board was established under section 406(i) of the General Education Provisions Act (GEPA) as amended by section 3403 of the National Assessment of Educational Progress Improvement Act (NAEP Improvement Act), Title III–C of the Augustus F. Hawkins—Robert T. Stafford Elementary and Secondary School Improvement Amendments of 1988 (Pub. L. 100–297), (20 U.S.C. 1221e–1).

The Board is established to formulate policy guidelines for the National Assessment of Educational Progress. The Board is responsible for selecting subject areas to be assessed, developing assessment objectives, identifying appropriate achievement goals for each grade and subject tested, and establishing standards and procedures for interstate and national comparisons.

On January 12, 1993, the Achievement Levels Committee of the National Assessment Governing Board will meet from noon until 4 p.m. This meeting will be closed to the public to permit the Committee to review preliminary, unreleased data from the 1992 reading assessment. Upon the completion of the review of this data, the Committee will formulate a recommendation for action by the Executive Committee.

On January 13 at 3 p.m., a joint teleconference of the Achievement Levels Committee and the Executive Committee will be held in closed session. During the joint meeting, the Executive Committee will review the recommendations from the Achievement Levels Committee regarding the setting of "cut scores" for the 1992 reading assessment. The Executive Committee will discuss these recommendations and, if appropriate, formulate a final recommendation for action by the full Board. Discussions during these two meetings will include references to specific items from the assessment, the disclosure of which would significantly frustrate implementation of the NAEP.

The results of the assessment must be presented in closed session because reference may be made to data which may be incorrect, incomplete, or misinterpreted. Premature disclosure of this data might significantly frustrate implementation of a proposed agency action. Such matters are protected by exemption 9(B) of section 552b(c) of title 5 U.S.C.

The full Board will convene via telephone conference in closed session from 1 p.m. to 3 p.m. on January 14, 1993, to review the recommendation from the joint Achievement Levels and Executive Committee meeting, and to take final action on the achievement levels for the 1992 reading assessment. The meeting will be closed to the public because the Board's deliberations will involve the review of preliminary unreleased data from the 1992 reading assessment. The discussion will include references to specific items from the assessment, the disclosure of which would significantly frustrate implementation of the NAEP. The results of the assessment must be presented in closed session because reference may be made to data which may be incorrect, incomplete, or misinterpreted. Premature disclosure of these data might significantly frustrate implementation of a proposed agency action. Such matters are protected by exemption 9(B) of section 552b(c) of title 5 U.S.C.

The public is being given less than fifteen days notice of this meeting since the committees' schedules and project timeliness did not allow the meeting to be set earlier.

A summary of the activities at the closed portion of the meeting and related matters, which are informative to the pubic consistent with the policy of 5 U.S.C. will be available to the public within fourteen days after the meeting.

Records are kept of all Board proceedings and are available for public inspection at the U.S. Department of Education, National Assessment Governing Board, suite 825, 800 North Capitol Street, NW., Washington, DC, from 8:30 a.m. to 5 p.m.

Roy Truby,

Executive Director, National Assessment Governing Board.

[FR Doc. 93–589 Filed 1–8–93; 8:45 am]

BILLING CODE 4000–01–M

DEPARTMENT OF ENERGY

Secretary of Energy Advisory Board Task Force on Radioactive Waste Management; Opportunity to Review and Comment on Draft Task Force Report

Pursuant to the Charter of the Secretary of Energy Advisory Board, notice is hereby given of the opportunity to review and comment on the draft report of the Secretary of Energy Advisory Board Task Force on Radioactive Waste Management. The draft report contains the Task Force's recommendations to the Secretary of Energy on measures the Department of Energy might take to strengthen public trust and confidence in its radioactive waste management activities.

The draft report will be available for review and copying in the Public Reading Room, 1E–190 Forrestal Building, 1000 Independence Avenue, SW., Washington, DC, between 9 a.m. and 4 p.m. Monday through Friday, except Federal Holidays. Single copies of the report will be available upon request by calling (202) 586–7092.

Persons wishing to submit written comment on the report should forward them to the individual listed below by Thursday, March 11, 1993, in order to receive full consideration.

Contact: Dr. Daniel Metlay, Designated Federal Officer, Secretary of Energy Advisory Board, AC–1, 1000 Independence Avenue, SW., Washington DC., 20585, (202) 586–7092.

Issued: Washington, DC, on: January 6, 1993.

Marcia L. Morris,

Deputy Advisory Committee Management Officer.

[FR Doc. 93–548 Filed 1–8–93; 8:45 am]

BILLING CODE 6450–01–M

Office of Energy Research

Energy Research Financial Assistance Program Notice 93–06: Mid-Latitude Atmospheric Ozone/UV–B Survey: Trends, Distributions, and Chemical Determinants

AGENCY: Department of Energy (DOE).

ACTION: Notice inviting grant applications.

SUMMARY: The Office of Health and Environmental Research (OHER) of the Department of Energy (DOE) hereby announces its interest in receiving applications to support DOE's evaluation of atmospheric ozone trends and distributions, the chemical determinants of atmospheric ozone concentrations, and the resulting perturbations of surface UV–B fluxes. The research activities conducted under this solicitation will focus specifically on mid-latitude phenomena, and will include analysis of ozone in the remote free troposphere as well as in the stratosphere. The remote free troposphere is defined for this program as that portion of the troposphere that exists above the planetary boundary layer and at extended distances from concentrated anthropogenic pollution sources, such as urban areas and industrial complexes.

DATES: Formal applications submitted in response to this notice must be received by the Acquisition and Assistance Management Division by 4:30 p.m., March 2, 1993, to be accepted for a merit review in April 1993 and to permit timely coordination for award in fiscal year 1993.

ADDRESSES: The application kit and guide for the ER Special Research Grant Program is available from the U.S. Department of Energy, Office of Health and Environmental Research, Environmental Sciences Division, ER–74, Washington, DC 20585. Telephone requests may be made by calling (301) 903–4208. Formal applications referencing Program Notice 93–06 should be forwarded to: U.S. Department of Energy, Office of Energy Research, Acquisition and Assistance Management Division, ER–64, Washington, DC 20585, ATTN: Program Notice 93–06. The following address must be used when submitting applications by U.S. Postal Service Express, any commercial mail delivery service, or when hand carried by the applicant: U.S. Department of Energy, Office of Energy Research, Acquisition and Assistance Management Division, ER–64, 19901 Germantown Road, Germantown, MD 20874.

FOR FURTHER INFORMATION CONTACT: Mr. Michael Riches, Office of Health and Environmental Research, Environmental Sciences Division, ER–74, Washington, DC 20585, (301) 903–3264 or by OMNET at M. RICHES.

SUPPLEMENTARY INFORMATION: This solicitation is funded under the Ozone Project of the DOE Atmospheric Chemistry Program (ACP). (Supporting documentation for the Ozone Project is available in the draft report entitled Overview of the ACP's Ozone Project, December 1992, and is available upon request from the office listed in "**ADDRESSES**" section of this notice.) The research is divided into two components, the first addressing ozone and UV–B trends, and the second dealing with reaction chemistry. Applications directed towards the first research component must address one or more of the following general questions:

(1) How reliable are the data currently used to evaluate vertical ozone distributions, ozone column loadings, and their trends?

(a) What are the errors associated with existing instrumentation, especially those involving altitude dependencies, chemical interferents, data-reduction algorithms, and physical interferents (e.g. clouds and aerosols)?

(b) What are the probable errors associated with measurement procedures and their changes?

(c) What are the statistical (sampling) errors associated with the sparse existing data set?

(2) How can the existing ozone data base be applied, possibly in conjunction with concurrent data bases for other atmospheric properties, to maximize reliable information regarding distributions, column loadings, and trends?

(3) What modifications to existing techniques and procedures can be made to increase the value of future data regarding ozone distributions and trends?

(4) How reliable are the data currently used to evaluate surface-level UV–B fluxes and their trends?

(a) What are the errors associated with existing instrumentation, especially those involving physical and chemical interferents, sensitivity drift, and wavelength resolution?

(b) What are the probable errors associated with procedural activities?

(c) What are the statistical (sampling) errors associated with the sparse existing data set?

(5) How can this existing UV–B data base be applied, possibly in conjunction with concurrent observations of other atmospheric properties, to maximize reliable information regarding surface fluxes and their trends?

(6) What modifications to existing techniques and procedures can be made to increase the value of future data regarding UV–B surface fluxes and trends?

Although individual research applications are expected to deal with subsets of these questions, the goal is that the funded applications will provide a complete as possible evaluation of all primary surface UV–B and ozone measurement methods, including surface-based and satellite remote sensing, balloon platforms, and rocket-based measurement systems. Total ozone column measurements, as well as ozone profiling measurements will be included. The application of combined data sets (e.g. for co-existing pollutants, clouds, etc.) for interpretive analyses is encouraged.

The second component of this research addresses sensitivities and uncertainties associated with chemical-kinetics parameterizations currently being used for simulating ozone formation/destruction chemistry in global models. In essence this component is intended to examine existing kinetics parameterizations under various temperature, pressure, pollutant-mix, and radiative conditions to evaluate:

- Sensitivities of predicted ozone concentrations (or reaction rates) to rate-coefficient values for each of the reactions simulated in a chosen parameterization;
- Sensitivities of predicted ozone concentrations (or reaction rates) to temperature, pressure, pollutant-mix, and radiative conditions;
- Uncertainties associated with the values of these parameters; and
- The collective uncertainty in ozone concentration (or reaction rate) corresponding to these individual sensitivity/uncertainty values.

This second research component is not intended to involve the use of multidimensional transport models. It focuses, rather, on the reaction-kinetics components of these models, which can be executed essentially as zero-dimensional, time-variant simulations, using state-of-the-art sensitivity analysis techniques. Applications addressing this component should explicitly state the scientific approach to be followed, including the reaction-kinetics parameterizations to be investigated, parameters and parameter ranges to be scrutinized, the statistical basis for the parametric experiment design, the sensitivity-analysis technique to be applied, and the techniques to be used for aggregating individual uncertainties to obtain composite values.

It is anticipated that three to five grants will be awarded for a 3-year period during FY 1993. Contingent upon availability of appropriated funds, approximately $1M per year is expected.

Information about submission of applications, eligibility, limitations, evaluation and selection processes, and other policies and procedures may be found in the ER Special Research Grant

Application Kit and Guide and 10 CFR Part 605.

The Catalog of Federal Domestic Assistance Number for this program is 81.049.

Issued in Washington, DC, on December 30, 1992.

D.D. Mayhew,

Director, Office of Management, Office of Energy Research.

[FR Doc. 93–549 Filed 1–8–93; 8:45 am]

BILLING CODE 6450–01–M

Federal Energy Regulatory Commission

[Project Nos. 10395, 10646, 11053 Kentucky]

The City of Augusta, et al.; Availability of Environmental Assessment

January 5, 1993

In accordance with the National Environmental Policy Act of 1969 and the Federal Energy Regulatory Commission's (Commission's) regulations, 18 CFR part 380 (Order No. 486, 52 FR 47897), the Office of Hydropower Licensing has reviewed the competing applications for major license for the proposed Meldahl Hydroelectric Project located on the Ohio River in Bracken County, near the City of Augusta, Kentucky, and has prepared a Comparative Environmental Assessment (CEA) for the proposed project. In the CEA, the Commission's staff has analyzed the potential environmental impacts of the proposed project and has concluded that approval of the proposed project, with appropriate mitigative measures, would not constitute a major Federal action significantly affecting the quality of the human enviroment.

Copies of the CEA are available for review in the Public Reference Branch, room 3308, of the Commission's offices at 941 North Capitol Street, NE., Washington, DC 20426.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–504 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. TM–3–9–20–000]

Algonquin Gas Transmission Co.; Proposed Changes in FERC Gas Tariff

January 5, 1993

Take notice that Algonquin Gas Transmission Company ("Algonquin") on December 30, 1992, tendered for filing proposed changes in its FERC Gas Tariff, Third Revised Volume No. 1, as set forth in the following revised tariff sheets:

Proposed to be effective December 1, 1992
1 Rev 12 Rev Sheet No. 41
1 Rev 12 Rev Sheet No. 42

Algonquin states that the revised tariff sheets flow through rate changes in Texas Eastern Transmission Corporation's ("Texas Eastern's") Rate Schedules SS–2 and SS–3, which underlie Algonquin's Rate Schedule STB and SS–III, respectively. Pursuant to section 10 of Rate Schedule STB and section 9 of Rate Schedule SS–III in Algonquin's FERC Gas Tariff, Third Revised Volume No. 1, Algonquin is hereby filing the above sheets to track the latest changes filed by Texas Eastern on October 28, 1992.

Algonquin further states that Texas Eastern made its October 28 filing to comply with the terms and conditions of the Commission approved Stipulation and Agreement ("S&A") in Docket No. RP88–067 Phase II (PCB's). The Commission found the tariff sheets to be in satisfactory compliance with the S&A and approved them on December 16, 1992.

Algonquin notes that copies of this filing were served upon each affected party and interested state commissions.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with sections 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests should be filed on or before January 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–507 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP93–58–000]

ANR Pipeline Co.; Proposed Changes in FERC Gas Tariff

January 5, 1993

Take notice that ANR Pipeline Company ("ANR"), on December 30, 1992 tendered for filing as part of its First Revised Volume No. 1–A of its FERC Gas Tariff, six copies of First Revised Sheet Nos. 67 and 68.

ANR states that the referenced tariff sheets are being submitted to reflect a change in ANR's Order No. 497 Electronic Bulletin Board access procedures. ANR has requested that the Commission accept the tendered tariff sheets to become effective January 4, 1993.

ANR states that all of its Volume No. 1–A customers and interested State Commission have been apprised of this filing.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Commission, 825 N. Capitol Street, NE., Washington, DC 20426 by January 12, 1993, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure 18 CFR 385.211 and 385.214. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this application are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–508 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. TQ93–3–21–000; TM93–8–21–000]

Columbia Gas Transmission Corp.; Proposed Changes in FERC Gas Tariff

January 5, 1993.

Take notice that Columbia Gas Transmission Corporation (Columbia) on December 31, 1992, tendered for filing the following proposed changes to its FERC Gas Tariff, First Revised Volume No. 1 to be effective February 1, 1993.

Thirty-first Revised Sheet No. 26
Twenty-fourth Revised Sheet No. 26.1
Twenty-ninth Revised Sheet No. 26A
Twenty-fourth Revised Sheet No. 26A.1
Twenty-fifth Revised Sheet No. 26B
Twentieth Revised Sheet No. 26B.1
Twenty-seventh Revised Sheet No. 26C
Fourteenth Revised Sheet No. 26C.1
Twenty-first Revised Sheet No. 26D
Twenty-eight Revised Sheet No. 163

Columbia states the sales rates set forth on Twenty-fourth Revised Sheet No. 26.1 reflect a decrease of 13.16¢ per Dth in the commodity rate and an overall increase of $0.485 per Dth in the total demand rate when compared with the total CDS rates filed in Columbia's January 1, 1993 Interim PGA which was

filed on December 30, 1992 in Docket No. TF93–3–21. The transportation rates set forth on Fourteenth Revised Sheet No. 26C.1 and Twenty-first Revised Sheet No. 26D reflect a decrease of 0.38¢ per Dth in the Fuel Change component.

Columbia states that copies of the filing were served upon Columbia's jurisdictional customers and interested state commissions.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, Union Center Plaza Building, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with rules 211 and 214 of the Commission's Rules of Practice and Procedure. All such motions or protests should be filed on or before January 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of Columbia's filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–509 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. TM93–3–33–000]

El Paso Natural Gas Co.; Tariff Filing

January 5, 1993

Take notice that on December 31, 1992 El Paso Natural Gas Company ("El Paso"), gave notice, pursuant to part 154 of the Federal Energy Regulatory Commission ("Commission") Regulations under the Natural Gas Act, of a revision to El Paso's Throughput Surcharge subject to section 22, Take-or-Pay Buyout and Buydown Cost Recovery, contained in the General Terms and Conditions of El Paso's First Revised Volume No. 1–A Tariff. El Paso requests that the tendered tariff sheets be accepted for filing and permitted to become effective February 1, 1993.

El Paso states that on July 31, 1992 at Docket No. RP92–214–000, El Paso filed a general rate case to become effective September 1, 1992. In the filing, El Paso included an illustrative Thoughput Surcharge rate of $0.0450 per dth based upon buyout and buydown cost recovery filings made up to such filing date and an annual throughput underlying El Paso's proposed rates of 1,107,542,022 per dth.

El Paso states that on August 31, 1992 at Docket No. TM93–1–33–000, El Paso filed, among other things, a revision to its Throughput Surcharge effective October 1, 1992. In such filing El Paso revised the Throughput Surcharge to $0.0349 per dth and stated that it had used throughput levels for purposes of the filing based upon the throughput levels underlying its currently effective rates at Docket No. RP91–188–000. Additionally, El Paso stated in such filing that it would file, with appropriate notice as required by the Commission's Regulations, a Throughput Surcharge rate to reflect the throughput levels underlying the rates at Docket No. RP92–214–000 to be effective upon the date such rates are placed into effect. By order issued September 30, 1992 at Docket No. TM93–1–33–000, the Commission accepted El Paso's proposed Throughput Surcharge of $0.0349 per dth effective October 1, 1992, which rate is currently in effect.

El Paso further states that the tendered tariff sheets, when accepted by the Commission and permitted to become effective, serve to update the Throughput Surcharge based on the throughput levels underlying El Paso's proposed rates at Docket No. RP92–214–000 which, upon motion, will become effective February 1, 1993.

El Paso states that copies of the filing are being served upon all of El Paso's interstate pipeline transportation and sales customers and all interested state regulatory commissions.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with 18 CFR 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests should be filed on or before January 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the public reference room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–510 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP93–57–000]

El Paso Natural Gas Co.; Tariff Filing

January 5, 1993

Take notice that on December 30, 1992, El Paso Natural Gas Company ("El Paso") tendered for filing, pursuant to part 154 of the Federal Energy Regulatory Commission's ("Commission") Regulations Under the Natural Gas Act certain tariff sheets which reflect revisions to the existing creditworthiness provisions contained its First Revised Volume No. 1–A Tariff and add a creditworthiness provision to its Second Revised Volume No. 1 Tariff.

El Paso states that by order issued July 2, 1992 at Docket No. RP92–185–000, the Commission, among other things, rejected certain tariff sheets containing creditworthiness provisions without prejudice to El Paso refiling them consistent with the Commission's discussion in the text of the order. El Paso and El Paso Electric Company filed requests for rehearing of the July 2, 1992 order.

El Paso states that on December 3, 1992 at Docket Nos. RP92–185–000, 001 and 002, the Commission issued an order which, among other things, granted in part and denied in part requests for rehearing and directed El Paso to refile certain currently effective tariff sheets containing creditworthiness provisions. Said order also permitted El Paso to refile, as its option, certain modified tariff sheets consistent with Commission precedent and El Paso's explanation of certain terms and conditions set forth in its request for rehearing.

El Paso states that as to the revisions directed by the Commission, it is refiling its creditworthiness provisions to clarify that El Paso will not suspend service to a bankrupt customer in a manner that is inconsistent with the Federal Bankruptcy Code. El Paso is also providing appropriate clarification within certain sections of the same creditworthiness provisions of the tendered tariff sheets based on El Paso's explanation set forth in its request for rehearing. In addition, El Paso is tendering for its Volume No. 1 Tariff a revised tariff sheet, which adds a new Section 6.5, Creditworthiness, and incorporates the revisions described therein.

El Paso has requested that the tariff sheets be accepted for filing and permitted to become effective February 1, 1993, which is not less than thirty (30) days after the date of filing.

El Paso states that copies of the filing are being served upon all of El Paso's interstate pipeline transportation and

sales customers and all interested state regulatory commissions.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with 18 CFR 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests should be filed on or before January 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the public reference room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–511 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. TQ93–3–34–000]

Florida Gas Transmission Co.; Proposed Changes in FERC Gas Tariff

January 5, 1993.

Take notice that on December 30, 1992 Florida Gas Transmission Company (FGT) tendered for filing as part of its FERC Gas Tariff, Second Revised Volume No. 1, the following tariff sheets to be effective February 1, 1993:

Thirty-Sixth Revised Sheet No. 8
Seventh Revised Sheet No. 222
Eighth Revised Sheet No. 223
Eighth Revised Sheet No. 228

FGT states that Thirty-Sixth Revised Sheet No. 8 is being filed in accordance with § 154.308 of the Commission's Regulations and pursuant to Section 15 of FGT's FERC Gas Tariff, Second Revised Volume No. 1 to reflect a decrease in FGT's jurisdictional rates due to a decrease in its average cost of gas purchased from that reflected in its Quarterly PGA filing, Docket No. TQ93–2–34–000, effective November 1, 1992.

FGT further states that its projected purchase cost of gas for the period February, 1993 through April, 1993, shown in detail on Schedule Q1, represents a decrease from $3.0677/MMBtu saturated, as reflected in FGT's Quarterly PGA filing in Docket No. TQ93–2–34–000, effective November 1, 1992 to $2.8014/MMBtu saturated in the instant filing.

FGT is required to update its Index of Entitlements concurrently with its Quarterly PGA filing pursuant to Section 9 of the General Terms and Conditions of its Tariff and has included such changes in Seventh Revised Sheet No. 222, and Eighth Revised Sheet Nos. 223 and 228.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426 in accordance with §§ 385.211 and 385.214 of the Commission's Rules and Regulations. All such motions or protests should be filed on or before January 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene.

Copies of this filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–512 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP93–62–000]

Equitrans, Inc.; Notice of Proposed Changes in FERC Gas Tariff

January 5, 1993

Take notice that on December 31, 1992, Equitrans, Inc. ("Equitrans") tendered for filing proposed changes in its FERC Gas Tariff reflecting a rat change from currently effective rates and other changes in its tariff. The proposed changes would increase revenues from jurisdictional services by $5,178,837 based on costs for the twelve (12) month period ending August 31, 1992, as adjusted. Equitrans states that this rate increases is necessitated by increases in costs necessary to operate and maintain its pipeline.

Equitrans submits primary tariff sheets which it proposes to implement in coordination with its restructuring compliance filing in Docket No. RS92–15, and its certificate application filing in Docket No. CP93–44–000. The rates, terms and conditions reflected in the primary sheets reflect various new or expanded services including no-notice transportation service and open access firm and interruptible storage service, which are required by Order No. 636. In addition, Equitrans proposes to apply the cost allocation and rate design principles directed by Order No. 636, including the adoption of straight fixed-variable rate design, removal of costs related to Equitrans' merchant function from the cost of service, and the reallocation of storage costs among services.

In accordance with Order No. 636, Equitrans proposes to recover $40,629,504 in transition costs related to stranded production and gathering facilities and products extraction. Equitrans proposes to amortize these costs over a four-year period and to collect these costs through a demand surcharge applied to all Part 284 transportation.

Equitrans is requesting that the primary tariff sheets under which open access storage service will be rendered be made effective on April 1, 1992, the beginning of the traditional storage injection season, and that the balance of the primary tariff sheets become effective on July 1, 1993, the date that Equitrans contemplates its Order No. 636 Compliance Filing will become effective. Equitrans requests whatever waivers may be necessary for the Commission to make the tariff sheets effective on the dates requested subject to refund.

Equitrans states that copies of the filing were served upon Equitrans jurisdictional customers and interested state commissions.

Any person desiring to be heard or to protest said filing should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capital Street, Washington, DC 20426 in accordance with Rule 211 and 214 of the commission's Rules of Practice and Procedures. All such petitions or protests should be filed on or before January 12, 1993. Protests will be considered by the Commission in determining appropriate action, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filings are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–502 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket Nos. TM93–9–4–000 and RP91–164–008]

Granite State Gas Transmission, Inc.; Notice of Proposed Changes in Rates and Tariff Provisions

January 5, 1993.

Take notice that on December 29, 1992, Granite State Gas Transmission, Inc. (Granite State), 300 Friberg Parkway, Westborough, Massachusetts 01581 filed the revised tariff sheets listed below in its FERC Gas Tariff, First

Revised Volume No. 2, containing changes in rates and tariff provisions for effectiveness on the dates indicated:

Proposed Effective Date: July 1, 1992

Second Revised Sheet No. 5
Second Revised Sheet No. 15
Second Revised Sheet No. 25
Second Revised Sheet No. 26
Second Revised Sheet No. 36

Proposed Effective Date: January 1, 1993

Third Revised Sheet No. 8
Fourth Revised Sheet No. 18
Sixth Revised Sheet No. 28
Fourth Revised Sheet No. 39
Second Revised Sheet No. 39A
Third Revised Sheet No. 62
Third Revised Sheet No. 63
Third Revised Sheet No. 72
Third Revised Sheet No. 73

According to Granite State, all of the above listed revised tariff sheets reflect either rate changes or changes in the tariff provisions in its Rate Schedules T–1 through T–6 pursuant to which Granite State provides transportation services for its affiliated distribution company customers, Bay State Gas Company and Northern Utilities, Inc. Granite State further states that Tennessee Gas Pipeline Company (Tennessee) provides the transportation services for Granite State's account and Granite State's transportation rate schedules are modelled on Tennessee's underlying rate schedules. It is further stated that Granite State is authorized to track changes in Tennessee's underlying rate schedules.

According to Granite State, the revised tariff sheets listed above for effectiveness on July 1, 1992 reflect a change in the Fuel Use percentages in its Rate Schedules T–1 through T–4 to track changes in the Fuel Use percentages which Tennessee filed in the underlying rate schedules as part of its compliance filing in Docket Nos. RP86–119 and RP88–229, *et al.*, for effectiveness on July 1, 1992.

Granite State further states that the revised tariff sheets listed above for effectiveness on January 1, 1993 reflect: (1) Tracking Tennessee's filings in the underlying rate schedules to include the demand charge component of the interim Gas Research Institute (GRI) funding unit for 1993 approved by the Commission in Docket No. RP92–133–000 (Phase I) and (2) compliance with the requirements of Granite State's rate settlement in Docket No. RP91–164–000, approved by the Commission on June 29, 1992. According to Granite State, the demand component of the interim GRI funding unit is applicable to its firm Rate Schedules T–4, T–5 and T–6. It is further stated that the rate revisions in compliance with the settlement in Docket No. RP91–164–000 establish lower "Seller's System Charges" in all of Granite State's transportation rate schedules as prescribed for the Phase 2 rate period.

Granite State further states that copies of its filing were served upon its customers and the regulatory commissions of the states of Maine, Massachusetts and New Hampshire.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426 in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214. All such motions or protests should be filed on or before January 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party to the proceeding or to participate as a party in any hearing therein must file a motion to intervene in accordance with the Commission's Rules. Copies of this filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–513 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP93–59–000]

High Island Offshore System; Proposed Changes in FERC Gas Tariff

January 5, 1993

Take notice that on December 31, 1992, High Island Offshore System ("HIOS") filed, pursuant to section 4 of the Natural Gas Act, for a general increase in its transportation rates, proposing an effective date of February 1, 1993.

According to the filing, HIOS attributes the need for an increase in rates to increases in operating and maintenance expenses and other increases in its cost of service as well as declining levels of firm service contracts and transportation volumes on its system. HIOS states that the increase reflects the inclusion of the ACA charge as an operating and maintenance expense in lieu of such charge's past recovery as a rate surcharge.

HIOS states that, based upon volumes transported during the base period, as adjusted, the proposed rates will result in an increase in annual revenues to HIOS of approximately $11.5 million when compared to the annual revenues generated by currently effective rates in effect subject to refund in Docket No. RP92–50. However, HIOS also states that the proposed rates reflect a decrease of approximately $2.8 million in HIOS' cost of service underlying its currently effective rates being collected subject to refund in Docket No. RP92–50.

HIOS requests the removal of the 100% load factor rate design condition for designing its rate, which was imposed in Docket Nos. CP75–104, *et al.*

HIOS also requests removal of the biennial rate filing requirement that was imposed in Docket Nos. CP75–104, *et al.*

HIOS states that copies of the filing have been served on all affected shippers.

Any person desiring to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with Rule 211 and Rule 214 of the Commission's Rules of Practice and Procedures, 18 CFR 385.211 and 385.214. All protests and motions to intervene should be filed on or before January 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–514 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. TQ93–5–25–000]

Mississippi River Transmission Corp.; Notice of Rate Change Filing

January 5, 1993

Take notice that on December 30, 1992, Mississippi River Transmission Corporation (MRT) tendered for filing Fifth Revised Eighty-Third Revised Sheet No. 4 and Fifth Revised Forty-Second Revised Sheet No. 4.1 to its FERC Gas Tariff, Second Revised Volume No. 1 to be effective January 1, 1993. MRT states that the purpose of the instant filing is to reflect an out-of-cycle purchase gas cost adjustment (PGA).

MRT states that Fifth Revised Eighty-Third Revised Sheet No. 4 and Fifth Revised Forty-Second Revised Sheet No. 4.1 reflect a decrease of 17.79 cents per MMBtu in the commodity cost of purchased gas from PGA rates filed on November 30, 1992 to be effective

December 1, 1992, in Docket No. TQ93–4–25–000. MRT also states that since the November 30, 1992 filing date, MRT has experienced changes in purchase and transportation costs for its system supply that could not have been reflected in that filing under current Commission regulations. MRT states that the revised tariff sheets also contain the 1993 GAs Research Institute (GRI) surcharges previously submitted by MRT in Docket No. TM93–4–25–000.

MRT states that a copy of this filing has been served on all of MRT's jurisdictional sales customers and to the State Commissions of Arkansas, Illinois and Missouri.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with §§ 385.211 and 385.214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214. All such motions or protests should be filed on or before January 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 92–503 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. CP93–98–000]

Gas Company of New Mexico, A Division of Public Service Company of New Mexico; Application for a Presidential Permit for the Construction, Operation and Maintenance and Connection at the United States/Mexico International Boundary of Facilities for the Export of Natural Gas

January 5, 1993.

Take notice that on December 7, 1992, Gas Company of New Mexico, a Division of Public Service Company of New Mexico (GCNM), Alvarado Square, Albuquerque, New Mexico 87158, filed an application pursuant to section 3 of the Natural Gas Act (NGA), as amended, 15 U.S.C. 717(b); Sections 153.1 *et seq.* and 153.10 *et seq.* of the Commission's Regulations, 18 CFR 153.1 and 153.10, Executive Order Nos. 10485 and 12038, and the Secretary of Energy's Delegation Order No. 0204–112, for a Presidential Permit authorizing construction of certain facilities at the international border with Mexico. GCNM requests authority to construct, connect, operate and maintain facilities for the purpose of exporting natural gas to Mexico, all as more fully set forth in the application on file with the Commission and open to public inspection.

GCNM indicates that it has contemporaneously filed an application with the Department of Energy's Office of Fossil Energy (DOE/FE) requesting authority to export natural gas to Mexico. GCNM states that the proposed facilities will be constructed under an agreement with Petroleos Mexicanos, S.A. (PEMEX), or its designee. GCNM states that the proposed facilities will permit the interconnection of GCNM's distribution facilities with the transmission system of PEMEX or PEMEX's designee at a point on the international boundary at the Santa Teresa Port of Entry. GCNM further states that Commission approval of the proposed construction will not involve a major federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. 4332(2)(c). GCNM also states that it includes a detailed Environmental Assessment which elaborates on the proposed construction and operation of the proposed facilities.

GCNM states that it plans to extend additional natural gas service into the region northwest and west of Sunland Park by constructing two pipelines and a Meter Station. One pipeline, the Chamberino-Foamex Gas Line, will interconnect with the El Paso Natural Gas California Main Line (EPNG) near Chamberino, NM, and transport gas from EPNG to the Foamex Regulator Station located at the Rail-Air Industrial Park. This pipeline will be approximately 17.5 miles long, and 8-inches in diameter. This pipeline will provide additional capacity to the Rail-Air Industrial Park and to the distribution trunk line between the industrial Park and Sunland Park, NM. The second pipeline, the Foamex-Santa Teresa Gas Line, and the Meter Station will be constructed to supply gas to customers in the Santa Teresa International Center area. This pipeline will be an 8-inch diameter underground gas transmission pipe approximately 1800 feet-long.

Any person desiring to be heard or to make any protest with reference to said application should on or before January 26, 1993, file with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, a motion to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.214 or 385.211). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a motion to intervene in accordance with the Commission's Rules.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–505 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. TA93–1–59–000]

Northern Natural Gas Co., Notice of Purchased Gas Cost Annual Filing

January 5, 1993.

Take notice that on December 31, 1992 Northern Natural Gas Company, (Northern), tendered for filing, as part of Northern's F.E.R.C. Gas Tariff its 1993 Annual PGA Filing, pursuant to Section 154.305 of the Commission's Regulations and as required by Commission Order Nos. 483 and 483–A. This filing is substantially different than previous Annual PGA filings as a result of the Commission's Order Approving Settlement with Modifications issued June 26, 1992. In Docket Nos. RP88–259 and RP89–1227, et. al., approving the New Service Settlement (Settlement). Northern states that in accordance with the Settlement, this Annual PGA filing reflects fourteen months of data (August 1991 through October 1992).

In the Settlement, Northern unbundled its sales from its throughput capacity and provided that it will establish its monthly commodity price by means of a Monthly Declared Price (MDP) which includes the R, N, and C structure similar to what was in effect in the Interim Gas Inventory Charge mechanism. However, effective November 1, 1992, Northern's MDP is determined in conjunction with a marker price.

On December 2, 1992 the Commission issued an Order in TA92–1–59–002, 003, 005 relating to the 1992 Annual PGA filing. In that Order, the Commission required Northern to refile, within 60 days, certain revisions to correct the carrying charge calculations. Northern states that its instant filing does not incorporate the effect of those required change, if any. However, when Northern files its compliance with the December 2, 1992 Order, Northern

expounds that it will also refile, if necessary, any schedules within its 1993 Annual PGA filing.

Northern states that within its 1993 Annual PGA filing:

(1) Northern is not proposing to change its currently effective Canadian-As-Billed (CAB) demand charge of $0.139, which was approved by the Commission on October 29, 1992.

(2) Northern will use the flex PGA process and the Marker Price structure to establish rates for 1993 pursuant to the terms of the New Service Settlement.

(3) No adjustment is made for the Reconciliation Adjustment (Surcharge). In the Compliance filing for New Services and Docket No. RP92–228, Northern received approval of the Reconciliation Adjustment and simultaneously filed to defer the increase effective January 1, 1993.

(4) Northern's actual gas purchase costs for each assessment interval of the Purchased Gas Assessment Test were less than 103% of the computed projected purchased gas costs.

Any person desiring to be heard or to protest said filing should file a petition to Intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426. In accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). All such petitions or protests should be filed on or before January 21, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–515 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. CP93–117–000]

San Diego Gas and Electric Co.; Application for a Presidential Permit and Section 3 Authorization to Construct and Operate an Export Point at the United States/Mexican Border, and Also for a Blanket Certificate

January 5, 1993

Take notice that on December 16, 1992, San Diego Gas and Electric Company (SDG&E), Post Office Box 1831, San Diego, California 92112, filed in Docket No. CP93–117–000 for (1) an application pursuant to section 3 of the Natural Gas Act and under part 153 of the Commission's Regulations for approval to construct, connect, operate, and maintain certain pipeline and metering facilities in San Diego County, California, in the vicinity of the International Boundary between the United States and the Republic of Mexico, and (2) an application for a blanket certificate for certain transportation, sales, and assignments pursuant to part 284 of the Commission's Regulations.

Section 3 and Presidential Permit

In particular SDG&E proposes to construct an operate the following facilities (the Otay Mesa Extension):

(1) 2.1 miles of 36-inch diameter pipeline extending from SDG&E's existing local distribution system in San Diego County, California to the International Boundary and;

(2) A metering station near the International Boundary.

The proposed facilities would have a capacity of 500 MMcf per day. SDG&E estimates that the facilities will cost about $3,640,000 and will be financed with internally generated funds and/or new debt or equity.

SDG&E states that the Otay Mesa Extension will be used to provide, in conjunction with Southern California Gas Company (SoCal), a transportation service from receipt points on the SoCal system to the border under § 284.224 of the Commission's Regulations. A connecting pipeline, will be built on the Mexican side of the border and be operated by Petroleos Mexicanos. SDG&E states, this will link its facilities with a power plant at Rosarito, Baja California.

Blanket Certificate

SDG&E states that it is exempt from the Commission's jurisdiction under section 1(c) of the Natural Gas Act. It proposes to transport certain volumes of natural gas produced outside of California to a point at the International Boundary between the United States and the Republic of Mexico. SDG&E seeks a blanket certificate under § 284.224 of the Commissions Regulations to perform such transportation. SDG&E further states that it may from time to time engage in other sales, transportation, or exchanges authorized by the blanket certificate that it seeks.

SDG&E states that it and SoCal will offer the transportation service on an open access basis. The rates for that service will be on file with, and approved by, the California Public Utilities Commission. Shippers will be required to obtain the proper export authorization from the Department of Energy, Office of Fossil Energy.

SDG&E and SoCal have jointly filed a related Joint Petition for Declaratory Order which is being noticed separately.

Any person desiring to be heard or to make any protest with reference to said application should on or before January 26, 1993, file with the Federal Energy Regulatory Commission, Washington, DC 20426, a motion to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.211 or 385.214) and the Regulations under the Natural Gas Act (18 CFR 157.10). All Protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants party to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a motion to intervene in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to jurisdiction conferred upon the Federal Energy Regulatory Commission by sections 3, 7, and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this application if no motion to intervene is filed within the time required herein, if the Commission on its own review of the matter finds that a grant of the certificate is required by the public convenience and necessity. If a motion to intervene is timely filed or if the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Applicant to appear or be represented at the hearing.

Linwood A Watson, Jr.,

Acting Secretary.

[FR Doc. 93–506 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. CP93–138–000]

Sea Robin Pipeline Co.; Notice of Application

January 5, 1993.

Take notice that on December 30, 1992, Sea Robin Pipeline Company (Sea Robin), P.O. Box 2563, Birmingham, Alabama 35202–2563, filed in Docket No. CP93–138–000 an application pursuant to Section 7(b) of the Natural

Gas Act for permission and approval to abandon a transportation service it performs for Tennessee Gas Pipeline Company (Tennessee), all as more fully set forth in the application on file with the Commission and open to public inspection.

Sea Robin proposes to abandon a transportation service performed for Tennessee under a September 29, 1971, agreement, as amended, on file as Sea Robin's Rate Schedule X–4.[1] Sea Robin states that it is authorized to transport up to 10,050 Mcf of gas per day from various locations offshore Louisiana to an interconnection with Columbia Gulf Transmission Company at the terminus of Sea Robin's pipeline near Erath, Vermilion Parish, Louisiana. Sea Robin advises that, although the primary term of the agreement expired on March 12, 1992, the agreement has continued in effect under the provisions of an evergreen clause. Further, Sea Robin advises that it is willing to waive the six month notice provision otherwise required for cancellation of the agreement. Sea Robin proposes that the abandonment authorization become effective December 31, 1992, stating that Tennessee has requested the abandonment of service under the X–4 Rate Schedule in order that replacement service may be implemented under new agreements with Sea Robin for IT and FT service under Sea Robin's part 284 tariff.

Any person desiring to be heard or to make any protest with reference to said application should on or before January 26, 1993, file with the Federal Energy Regulatory Commission, Washington, DC 20426, a motion to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.214 or 385.211) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a motion to intervene in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by sections 7 and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this application if no motion to intervene is filed within the time required herein, if the Commission on its own review of the matter finds that permission and approval for the proposed abandonment are required by the public convenience and necessity. If a motion for leave to intervene is timely filed, or if the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Sea Robin to appear or be represented at the hearing.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–500 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[1] See 51 FPC 645, and 52 FERC ¶ 62,157.

[Docket No. CP93–119–000]

Southern California Gas Co. and San Diego Gas and Electric Co.; Notice of Joint Petition for Declaratory Order

January 5, 1993.

Take notice that on December 16, 1992, Southern California Gas Company (SoCalGas), 555 West Fifth Street, Los Angeles, California 90013–7011 and San Diego Gas and Electric Company (SDG&E), P.O. Box 1831, San Diego, California 92112 filed a joint petition pursuant to Rule 207 of the Commission's Rules of Practice and Procedure (18 CFR 385.207). They are requesting that the Commission issue an order declaring that certain facilities to be built by SoCalGas and SDG&E are not subject to the Commission's jurisdiction under the Natural Gas Act, all as more fully set forth in the petition which is on file with the Commission and open to public inspection.

SoCalGas and SDG&E state that SDG&E is concurrently seeking in Docket No. CP93–117–000 authorization under Section 3 of the Natural Gas Act and a Presidential Permit to construct and operate facilities in San Diego County, California to export up to 500 MMcf per day of gas to the Republic of Mexico and SDG&E is also seeking a blanket certificate under § 284.224 of the Commission's Regulations. In addition to SDG&E's export facilities SoCalGas and SDG&E state in this docket (Docket No. CP93–119–000) that the gas to be transported to Mexico will flow primarily through existing facilities. However both SoCalGas and SDG&E are building facilities upstream of the proposed export point.

SoCalGas and SDG&E state that the new facilities will become integral parts of their distribution systems serving both native-load customers and the new export point. Thus they say the facilities should remain under the jurisdiction of the California Public Utilities Commission (CPUC) and should not be regulated by the Commission. SoCalGas and SDG&E seek a declaratory order from the Commission affirming their view of the jurisdictionality of the new facilities.

SoCalGas and SDG&E state that the transportation services through the facilities described in this docket will be authorized under § 284.224 of the Commission's Regulations. SoCalGas was issued a Blanket Certificate in 41 FERC ¶ 61,173. SDG&E is requesting a Blanket Certificate in Docket No. CP93–117–000.

Any person desiring to be heard or to make any protest with reference to said petition should on or before January 26, 1993, file with the Federal Energy Regulatory Commission, Washington DC 20426, a motion to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.214 or 385.211). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a motion to intervene in accordance with the Commission's Rules.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–516 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP93–54–000]

Texas Eastern Transmission Corp.; Notice of Proposed Changes in FERC Gas Tariff

January 5, 1993.

Take notice that Texas Eastern Transmission Corporation ("Texas Eastern") on December 30, 1992, resubmitted for filing as part of its Gas Tariff, Fifth Revised Volume No. 1, six copies of the following tariff sheets:

Proposed to be Effective November 1, 1992

Sub Revised Twenty-sixth Revised Sheet No. 51
Sub Revised Sixteenth Revised Sheet No. 51B
Sub Revised Sixteenth Revised Sheet No. 51D

Proposed to be Effective December 1, 1992

Sub Twenty-eighth Revised Sheet No. 51
Sub Eighteenth Revised Sheet No. 51B
Sub Eighteenth Revised Sheet No. 51D

Proposed to be Effective January 1, 1993

Sub Twenty-ninth Revised Sheet No. 51

Texas Eastern states that this resubmission is made pursuant to the Commission's November 30, 1992 Letter Order entitled "'Letter Order Pursuant to § 375.307 (b)(1) and (b)(2), OPPR Allocation and Rate Design Branch, Texas Eastern Transmission Corporation, Docket No. GT93–6–000." In its November 30, 1992 Letter Order the Commission rejected the tariff sheets listed above on grounds that Texas Eastern had failed to file the appropriate supporting schedules required by § 154.63(3)(b) of the Commission's regulations. The Commission's rejection was without prejudice to refiling the sheets in accordance with the requirements of the Commission's regulations.

Texas Eastern states that the tariff sheets rejected by the Commission were filed in accordance with prior orders of the Commission approving the CD–1 Adjustment Program service in Docket No. CP88–180. In particular, in such orders the Commission approved initial rates for the CD–1 Adjustment Program service which included an incremental demand surcharge to cover the cost of constructing the facilities to provide the service. Texas Eastern asserts that the resubmitted tariff sheets reflect such approved surcharge, pursuant to the Commission's June 21, 1991 order in Docket No. CP88–180–009. Accordingly, there is no rate change involved. Rather, the tariff sheets implement the Commission's orders by applying the incremental demand surcharge to the firm transportation service to which customers have converted as certificated by the Commission in Docket No. CP88–180. In light of the foregoing, Texas Eastern believes that good cause exists to permit the attached tariff sheets to become effective on November 1, 1992 and December 1, 1992 as set forth above. The surcharge effective December 1, 1992 reflects adjustments for PCB related costs and was approved pursuant to the Commission's order dated December 16, 1992 in Docket No. RP88–067–061 Phase II (PCBs). In this connection, Texas Eastern is filing contemporaneously herewith a protective request for Rehearing with respect to the November 30, 1992 order.

In addition, Texas Eastern states that on December 1, 1992, in Docket No. TM93–3–17–000, Texas Eastern filed as a part of its FERC Gas Tariff, Fifth Revised Volume No. 1, Twenty-ninth Revised Sheet No. 51 as one of the tariff sheets necessary to reflect an interim funding mechanism for the Gas Research Institute ("GRI") in Section 25 of the General Terms and Conditions ("GRI Filing"). The tariff sheets were submitted pursuant to the Commission's orders approving an interim GRI funding mechanism for 1993. Gas Reserach Institute, Order on Proposed Funding Mechanism, 60 F.E.R.C. Paragraph 61,203 (August 28, 1992), Order Denying Rehearing, issued October 28, 1992.

Texas Eastern asserts that in conjunction with the current filing, it submitted Sub Twenty-ninth Revised Sheet No. 51, which reflects the incremental demand surcharge for the CD–1 Adjustment Program service as approved in Docket No. CP88–180, to replace the Twenty-ninth Revised Sheet No. 51 included in the GRI Filing.

The proposed effective dates of the tariff sheets are November 1, 1992, December 1, 1992, and January 1, 1993, as indicated.

Texas Eastern states that copies of the filing were served on Texas Eastern's jurisdictional customers and interested state commissions. Copies of this filing have also been served on all parties on the service list in Docket No. CP88–180.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure. All such motions or protests should be filed on or before January 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–517 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. TM93–3–18–000]

Texas Gas Transmission Corp.; Notice of Proposed Changes in FERC Gas Tariff

January 5, 1993.

Take notice that on December 31, 1992, Texas Gas Transmission Corporation (Texas Gas) tendered for filing the revised tariff sheets contained in appendix A to the filing.

Texas Gas states that the proposed tariff sheets reflect changes to its Base Tariff Rates pursuant to the Transportation Cost Adjustment provisions contained in section 32 of its FERC Gas Tariff Original Volume No. 1 and section 27 of its FERC Gas Tariff First Revised Volume No. 2–A, and are proposed to be effective February 1, 1993.

Texas Gas states that copies of the filing were served on Texas Gas' jurisdictional sales customers, all parties on the Commission's official restricted service list in the consolidated proceedings, and interested state commissions.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with §§ 385.214 and 385.211 of the Commission's Rules and Regulations. All such protests or motions should be filed on or before January 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–518 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP93–55–000]

Trailblazer Pipeline Co.; Notice of Proposed Changes in FERC Gas Tariff

January 5, 1993

Take notice that on December 30, 1992, Trailblazer Pipeline Company (Trailblazer) tendered for filing as part of its FERC Gas Tariff, the tariff sheets listed in appendices A and B, attached to the filing, to become effective February 1, 1993. Trailblazer states that this filing is a general rate case submitted principally to comply with the terms of Trailblazer's last settlement at Docket No. RP84–94.

Trailblazer states that the filing reflects a base period encompassing the twelve months ended August 31, 1992, adjusted for known and measurable changes anticipated to occur during the nine month period ended May 31, 1993 Trailblazer notes that its filing also reflects a straight fixed-variable rate design, an equity return allowance of 15%, a higher depreciation rate, and reduced operation and maintenance expenses when compared to the level

established in Trailblazer's last rate case settlement at Docket No. RP84–94.

Trailblazer states that copies of the filing were served upon all of Trailblazer's jurisdictional customers and interested state regulatory agencies.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with 18 CFR 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests should be filed on or before January 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the public reference room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–519 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP93–56–000]

Transwestern Pipeline Co.; Notice of Proposed Changes in FERC Gas Tariff

January 5, 1993

Take notice that, on December 30, 1992, Transwestern Pipeline Company (Transwestern) tendered for filing as part of its FERC Gas Tariff, Second Revised Volume No. 1, the following tariff sheets:

Primary Tariff Sheets

Effective April 1, 1993:

100th Revised Sheet No. 5
Original Sheet No. 5E(v)
65th Revised Sheet No. 6
10th Revised Sheet No. 6C
1st Revised Sheet No. 6D
7th Revised Sheet No. 87
13th Revised Sheet No. 89
2nd Revised Sheet No. 89A
10th Revised Sheet No. 90
3rd Revised Sheet No. 92

Alternate Tariff Sheets

Effective April 1, 1993:

Alternate 100th Revised Sheet No. 5
6th Revised Sheet No. 5A
2nd Revised Sheet No. 5A.01
2nd Revised Sheet No. 5A.02
2nd Revised Sheet No. 5A.03
2nd Revised Sheet No. 5A.04
1st Revised Sheet No. 5A.05
4th Revised Sheet No. 5B
Alternate 10th Revised Sheet No. 90A

The above referenced tariff sheets are being filed by Transwestern to modify its take-or-pay, buy-out and buy-down mechanism ("Transition Cost Recovery" or "TCR" mechanism) in order to recover certain take-or-pay settlement, buy-out, buy-down, and contract reformation costs ("Transition Costs") which amounts it paid subsequent to the implementation date of its Gas Inventory Charge ("GIC"), October 1, 1989, and which do not qualify under the Litigation Exception provision of its tariff.

Transwestern has paid an additional $5,454,449.38 in Transition Costs ("TCR Amount Eleven") and is revising certain tariff sheets and requesting authority to begin recovery of such amounts under the tariff sheets.

Under the tariff sheets, Transwestern proposes to absorb twenty-five percent (25%) of the additional Transition Costs it has incurred and to recover the remaining seventy-five percent (75%) through an exit point, volumetric surcharge which includes a reconciliation or "true-up" mechanism that complies with Order Nos. 528–A and 528–B.

Transwestern respectfully requests that the Commission grant any and all waivers of its rules, regulations, and orders as may be necessary so as to permit the above listed tariff sheets to become effective April 1, 1993.

Transwestern states that copies of the filing have been mailed to each of its jurisdictional customers and interested state commissions.

Any person desiring to be heard or to protest said filing should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with Rules 214 and 211 of the Commission's Rules of Practice and Procedure (18 CFR 385.214 and 385.211). All such petitions or protests must be filed on or before January 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–520 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP93–61–000]

U–T Offshore System; Notice of Proposed Changes in FERC Gas Tariff

January 5, 1993.

Take notice that on December 31, 1992, U–T Offshore System ("U–TOS") filed, pursuant to section 4 of the Natural Gas Act, for a general increase in its transportation rates, proposing an effective date of February 1, 1993.

According to the filing, U–TOS attributes the need for an increase in rates to increases in operating and maintenance expenses and other increases in its cost of service (including its negative salvage rate) as well as declining levels of firm service contracts and transportation volumes on its system. U–TOS states that the increase reflects the inclusion of the ACA charge as an operating and maintenance expense in lieu of such charge's past recovery as a rate surcharge.

U–TOS states that, based upon volumes transported during the base period, as adjusted, the proposed rates will result in an increase in annual revenues to U–TOS of approximately $1.8 million when compared to the annual revenues generated by currently effective rates in effect subject to refund in Docket No. RP92–47.

U–TOS requests the removal of the 100% load factor rate design condition for designing its rate, which was imposed in Docket Nos. CP76–118, *et al.*

U–TOS also requests removal of the biennial rate filing requirement that was imposed in Docket Nos. CP76–118, *et al.*

U–TOS states that copies of the filing have been served on all affected shippers.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with 18 CFR 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests should be filed on or before January 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make Protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the public reference room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–501 Filed 1–8–93; 8:45 am]

BILLING CODE 6717–01–M

Western Area Power Administration

Transition from Guidelines and Acceptance Criteria to Integrated Resource Planning

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Transition to Integrated Resource Planning.

SUMMARY: In recognition of the intent of Congress in superseding title II of the Hoover Power Plant Act of 1984 through enactment of the Energy Policy Act of 1992, and in anticipation of the Western Area Power Administration's (Western) development of the Energy Planning and Management Program (Program), Western will no longer require customer compliance with the Guidelines and Acceptance Criteria for Customer Conservation and Renewable Energy Programs in order to facilitate the preparation of integrated resource plans by Western's long-term firm power customers.

FOR FURTHER INFORMATION CONTACT:

Robert C. Fullerton, Western Area Power Administration, P.O. Box 3402, Golden, CO 80401–3398. (303) 231–1679.

James D. Davies, Billings Area Office, Western Area Power Administration, P.O. Box 35800, Billings, MT 59107–5800. (406) 657–6532.

Stephen A. Fausett, Loveland Area Office, Western Area Power Administration, P.O. Box 3700, Loveland, CO 80539–3003. (303) 490–7201.

Thomas A. Hine, Phoenix Area Office, Western Area Power Administration, P.O. Box 6457, Phoenix, AZ 85005–6457. (602) 352–2453.

David G. Coleman, Sacramento Area Office, Western Area Power Administration, 1825 Bell Street, Suite 105, Sacramento, CA 95825–1097. (916) 649–4418.

Lloyd Greiner, Salt Lake City Area Office, Western Area Power Administration, P.O. Box 11606, Salt Lake City, UT 84147–0606. (801) 524–6372.

SUPPLEMENTARY INFORMATION: On October 24, 1992, the Energy Policy Act of 1992 became law. Section 114 of that legislation requires the preparation of integrated resource plans by the long-term firm power customers of Western. Section 114 also supersedes title II of the Hoover Plant of 1984 in its entirety. The Hoover Power Plant Act of 1984 was the statutory basis for Western's Guidelines and Acceptance Criteria for Customer Conservation and Renewable Energy Programs, 50 FR 33892 (August 21, 1985). To replace the Guidelines and Acceptance Criteria, Western is developing a Program that includes a requirement for all Western firm power customers to prepare an integrated resource plan consistent with the provisions of the Energy Policy Act. In recognition of the action of Congress, Western will no longer require customer compliance with the existing Guidelines and Acceptance Criteria so that customers can begin to focus their resources on the transition to preparation of quality integrated resource plans.

Issued in Golden, Colorado, December 29, 1992.

William H. Clagett,

Administrator.

[FR Doc. 93–550 Filed 1–8–93; 8:45 am]

BILLING CODE 6450–01–M

ENVIRONMENTAL PROTECTION AGENCY

[WH–FRL–4553–8]

State and Local Assistance; Grants for State Water Pollution Control Revolving Funds (Title VI) Under the Clean Water Act

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of allotment.

SUMMARY: The Departments of Veterans Affairs and Housing and Urban Development, and Independent Agencies Appropriations Act, 1993, (the Act) provides $1,927,500,000 to capitalize State Revolving Fund (SRF) programs authorized by title VI of the Clean Water Act (CWA). This notice sets forth the State allotments for fiscal year 1993 for their SRF programs. It also provides notice that one-half of one percentum of the appropriation, $9,637,500, is reserved for grants to Indian Tribes and Alaska Native Villages to construct sewage treatment facilities.

FOR FURTHER INFORMATION CONTACT: Mr. Leonard B. Fitch, Program Management Branch, Municipal Support Division, Office of Wastewater Enforcement and Compliance, (202) 260–5858.

SUPPLEMENTARY INFORMATION: Public Law 102–389, the Departments of Veterans Affairs and Housing and Urban Development, and Independent Agencies Appropriations Act, 1993, provides $1,927,500,000 to capitalize SRF programs authorized by title VI of the CWA. Section 604(a) of the CWA requires that funds appropriated for title VI for fiscal years 1987–1990 be allotted in accordance with the table in section 205(c)(3) of the CWA. Congress has given the Agency no instruction regarding the allotment of fiscal year 1993 funds. In the absence of Congressional action, the Agency will allot the fiscal year 1993 funds in accordance with the table in section 205(c)(3) except as described below.

Indian Tribes Adjustment

The Act authorizes the Administrator to reserve up to one half on one percentum of fiscal year 1993 title VI funds for making grants to Indian Tribes and Alaska Native Villages for construction of wastewater treatment facilities. The full amount is hereby reserved to be administered under the Indian Set-Aside Program authorized by section 518(c) of the CWA. These funds will be allotted to the Indian Tribes and Alaska Native Villages based on the 1990 Indian Set-Aside Project Priority List published in the **Federal Register** December 21, 1990. Projects were ranked on this Priority List based on water quality and public health criteria.

Trust Territory Adjustment

In Public Law 99–658, Congress approved a Compact of Free Association for the Trust Territories' members. Two entities, the Federated States of Micronesia and the Republic of the Marshall Islands have implemented Compacts and are no longer eligible for grants under title VI. At the effective date of this allotment the Republic of Palau has yet to implement a Compact of Free Association, and, under Public Law 99–239, section 105(h)(2), remains eligible for title VI grants. Funds that otherwise would have been allotted to the Federated States of Micronesia and the Republic of the Marshall Islands are redistributed to the States and Territories by proportionally increasing their respective shares of the appropriation as shown in the column titled "Allotment Formula After Trust Territory Adjustments." The actual allotments resulting from the adjusted allotment shares are shown in the column titled "fiscal year 1993 State Allotment." The table at the end of this notice lists the amount of funding made available to each State. These funds are available for obligation until September 30, 1994. Grants from the allotments may be awarded as of the date that the funds were issued to the Regional Administrators by the Comptroller of EPA.

Dated: January 4, 1993.

William K. Reilly,

Administrator.

State	Allotment formula	Allotment formula after trust terr. adjustments	FY 1993 state allotment
Alabama	0.011309	0.011320	$21,709,300
Alaska	0.006053	0.006058	11,619,600
Arizona	0.006831	0.006837	13,113,100
Arkansas	0.006616	0.006622	12,700,400
California	0.072333	0.072400	138,853,600
Colorado	0.008090	0.008098	15,529,900
Connecticut	0.012390	0.012402	23,784,400
Delaware	0.004965	0.004970	9,531,000
District of Columbia	0.004965	0.004970	9,531,000
Florida	0.034139	0.034171	65,534,700
Georgia	0.017100	0.017116	32,825,900
Hawaii	0.007833	0.007840	15,036,800
Idaho	0.004965	0.004970	9,531,000
Illinois	0.045741	0.045783	87,806,400
Indiana	0.024374	0.024397	46,786,400
Iowa	0.013688	0.013701	26,276,100
Kansas	0.009129	0.009137	17,524,400
Kentucky	0.012872	0.012884	24,709,700
Louisiana	0.011118	0.011128	21,342,600
Maine	0.007829	0.007836	15,028,900
Maryland	0.024461	0.024484	46,966,400
Massachusetts	0.034338	0.034370	65,916,700
Michigan	0.043487	0.043527	83,479,600
Minnesota	0.018589	0.018606	35,684,300
Mississippi	0.009112	0.009120	17,491,800
Missouri	0.028037	0.028063	53,821,100
Montana	0.004965	0.004970	9,531,000
Nebraska	0.005173	0.005178	9,930,300
Nevada	0.004965	0.004970	9,531,000
New Hampshire	0.010107	0.010116	19,401,800
New Jersey	0.041329	0.041367	79,337,000
New Mexico	0.004965	0.004970	9,531,000
New York	0.111632	0.111736	214,293,900
North Carolina	0.018253	0.018270	35,039,300
North Dakota	0.004965	0.004970	9,531,000
Ohio	0.058936	0.058989	109,296,800
Oklahoma	0.008171	0.008179	15,685,400
Oregon	0.011425	0.011436	21,931,900
Pennsylvania	0.040082	0.040099	76,904,800
Rhode Island	0.006791	0.006797	13,036,300
South Carolina	0.010361	0.010371	19,889,400
South Dakota	0.004965	0.004970	9,531,000
Tennessee	0.014692	0.014706	28,203,400
Texas	0.046226	0.046269	88,737,500
Utah	0.005329	0.005334	10,229,800
Vermont	0.004965	0.004970	9,531,000
Virginia	0.020698	0.020717	39,732,800
Washington	0.017588	0.017604	33,762,700
West Virginia	0.015766	0.015781	30,265,100
Wisconsin	0.027342	0.027367	52,486,900
Wyoming	0.004965	0.004970	9,531,000
American Samoa	0.000906	0.000909	1,743,000
Guam	0.000657	0.000658	1,261,200
Northern Marianas	0.000422	0.000422	810,200
Puerto Rico	0.013191	0.013203	25,322,000
Pacific Trust Terr	0.001295	0.001367	704,500
Virgin Islands	0.000527	0.000527	1,011,700
Subtotal	1.000000	1.000000	$1,917,862,500
Indian Set-Aside	.....	.....	$9,637,500
Total	.....	.....	$1,927,500,000

[FR Doc. 93–525 Filed 1–8–93; 8:45 a.m.]

BILLING CODE 6560-50-M

[FRL–4554–1]

Public Meeting of the Phosphoric Acid Production Waste Dialogue Committee

AGENCY: Environmental Protection Agency.

ACTION: Federal Advisory Committee meeting.

SUMMARY: As required by the Federal Advisory Committee Act, we are giving notice of the January meeting of the Phosphoric Acid Waste Dialogue Committee. The meeting is open to the public without advance registration.

The purpose of the meetings is to continue to review information on the issue of pollution prevention in the production of phosphoric acid.

DATES: The Committee meeting will be held on January 29, 1993 from 8:30 a.m. to 4 p.m.

ADDRESSES: The meeting will be held at the Marriott Airport Hotel, 7499 Augusta National Drive, Orlando, Florida.

FOR FURTHER INFORMATION CONTACT:

Persons needing further information on the technical or scientific matters related to phosphoric acid wastes should contact Dr. Daniel R. Bushman, Office of Pollution Prevention and Toxics, Economics, Exposure and Technology Division, TS 779, Environmental Protection Agency, Washington, DC 20460; phone (202) 260–6700. Persons needing further information on the committee's procedural and logistical matters should call Deborah Dalton, Consensus and Dispute Resolution Program, (202) 260–5495, or the Committee's facilitator, Greg Bourne, Southeast Negotiation Network, Georgia Institute of Technology, Atlanta, GA (404) 853–0846.

Dated: January 5, 1993.

Deborah Dalton,

Designated Federal Official, Office of Regulatory Management and Evaluation, Office of Policy, Planning and Evaluation.

[FR Doc. 93–523 Filed 1–8–93; 8:45 am]

BILLING CODE [illegible]

[FRL–4553–6]

Proposed Administrative Settlement Under Section 122(h) of the Comprehensive Environmental Response, Compensation, and Liability Act; Hooper Sands, South Berwick, ME

AGENCY: U.S. Environmental Protection Agency.

ACTION: Notice of proposed administrative settlement and request for public comment.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is proposing to enter into an administrative settlement to address claims under the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), 42 U.S.C. 9601. Notice is being published to inform the public of the proposed settlement and of the opportunity to comment. The settlement is intended to resolve the liability under CERCLA of the United States Department of the Navy for unrecovered costs incurred by EPA in conducting response actions at or in connection with the Hooper Sands Superfund Site in South Berwick, Maine through and including May 12, 1992.

DATES: Comments must be provided on or before February 10, 1993.

ADDRESSES: Comments should be addressed to the Docket Clerk, U.S. Environmental Protection Agency, Region I, JFK Federal Building—RCG, Boston, Massachusetts 02203, and should refer to: In the Matter of Hooper Sands Superfund Site, South Berwick, Maine, U.S. EPA Docket No. I–92–1082.

FOR FURTHER INFORMATION CONTACT: Kathleen Woodward, U.S. Environmental Protection Agency, Office of Regional Counsel, RCV, J.F.K. Federal Building, Boston, Massachusetts 02203, (617) 565–3687.

SUPPLEMENTARY INFORMATION: In accordance with section 122(i)(1) of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), 42 U.S.C. 9622(i)(1), notice is hereby given of a proposed administrative settlement concerning the Hooper Sands Superfund Site in South Berwick, ME. The settlement was approved by EPA Region I on December 4, 1992, subject to review by the public pursuant to this Notice. The United States Department of the Navy, the Settling Party, has executed a signature page committing it to participate in the settlement. Under the proposed settlement, the Settling Party is required to pay $728,209,81 to the Hazardous Substances Superfund. EPA believes the settlement is fair and in the public interest.

EPA is entering into this agreement under the authority of section 122(h) of CERCLA. Section 122(h) of CERCLA provides EPA with authority to consider, compromise, and settle a claim under section 107 of CERCLA for costs incurred by the United States if the claim has not been referred to the U.S. Department of Justice for further action. The U.S. Department of Justice approved this settlement in writing on November 17, 1992.

EPA will receive written comments relating to this settlement for thirty (30) days from the date of publication of this Notice.

A copy of the proposed administrative settlement may be obtained in person or by mail from the Docket Clerk, U.S. Environmental Protection Agency, Office of Regional Counsel, JFK Federal Building—RCG, Boston, Massachusetts 02203, (617) 565–3351.

The Agency's response to any comments received will be available for public inspection with the Docket Clerk, U.S. Environmental Protection Agency, Region I, JFK Federal Building—RCG, Boston, Massachusetts 02203 (U.S. EPA Docket No. I–92–1082).

Dated: December 4, 1992.

Paul Keough,

Acting Regional Administrator.

[FR Doc. 93–526 Filed 1–8–93; 8:45 am]

BILLING CODE [illegible]

[FRL–4553–5]

Proposed Administrative Settlement Under Section 122(h) of the Comprehensive Environmental Response, Compensation, and Liability Act; L.E. MacNair Building Superfund Site, Houlton, ME

AGENCY: U.S. Environmental Protection Agency.

ACTION: Notice of proposed adminisrative settlement and request for public comment.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is proposing to enter into an administrative settlement to address claims under the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), 42 U.S.C. 9601. Notice is being published to inform the public of the proposed settlement and of the opportunity to comment. The settlement is intended to resolve the liability under CERCLA of Bangor and Aroostook Railroad Company, G. Milton Carter, G.M. Nicholas Carter, L.E. MacNair Creditor Trust (David Edgar and John Rogers, Trustees; AFCO Credit Corporation, Bemis Company, and Stanford Holdings, Ltd., Beneficiaries), and Maine Potato Growers, Inc. for costs incurred by EPA in conducting response actions at the L.E. MacNair Building Superfund Site in Houlton, Maine.

DATES: Comments must be provided on or before February 10, 1993.

ADDRESSES: Comments should be addressed to the Docket Clerk, U.S. Environmental Protection Agency, Region I, JFK Federal Building—RCG, Boston, Massachusetts 02203, and should refer to: In the matter of L.E. MacNair Building Superfund Site, Houlton, ME, U.S. EPA Docket No. I–92–1100.

FOR FURTHER INFORMATION CONTACT: Andrew Raubvogel, U.S. Environmental Protection Agency, Office of Regional Counsel, RCV, J.F.K. Federal Building, Boston, Massachusetts 02203, (617) 565–3169.

SUPPLEMENTARY INFORMATION: In accordance with section 122(i)(1) of the

Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), 42 U.S.C. 9622(i)(1), notice is hereby given of a proposed administrative settlement concerning the L.E. MacNair Building Superfund Site in Houlton, ME. The settlement was approved by EPA Region I on December 16, 1992 subject to review by the public pursuant to this Notice. Bangor and Aroostook Railroad Company, G. Milton Carter, G.M. Nicholas Carter, the L.E. MacNair Creditor Trust (David Edgar and John Rogers, Trustees; AFCO Credit Corporation, Bemis Company, and Stanford Holdings, Ltd., Beneficiaries), and Maine Potato Growers, Inc., the Settling Parties, have executed signature pages committing it to participate in the settlement. Under the proposed settlement, the Settling Parties are required to pay $875,000 to the Hazardous Substances Superfund. EPA believes the settlement is fair and in the public interest.

EPA is entering into this agreement under the authority of section 122(h) of CERCLA. Section 122(h) of CERCLA provides EPA with authority to consider, compromise, and settle a claim under section 107 of CERCLA for costs incurred by the United States if the claim has not been referred to the U.S. Department of Justice for further action. The U.S. Department of Justice approved this settlement in writing on December 16, 1992.

EPA will receive written comments relating to this settlement for thirty (30) days from the date of publication of this Notice.

A copy of the proposed administrative settlement may be obtained in person or by mail from Andrew Raubvogel, U.S. Environmental Protection Agency, Office of Regional Counsel, JFK Federal Building—RCV, Boston, Massachusetts 02203, (617) 565–3169.

The Agency's response to any comments received will be available for public inspection with the Docket Clerk, U.S. Environmental Protection Agency, Region I, JFK Federal Building—RCG, Boston, Massachusetts (U.S. EPA Docket No. I–92–1100).

Dated: December 16, 1992.

Paul G. Keough,

Acting Regional Administrator.

[FR Doc. 93–527 Filed 1–8–93; 8:45 am]

BILLING CODE 6560–50–M

Proposed Administrative Settlement Pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act, as Amended by the Superfund Amendments and Reauthorization Act

AGENCY: Environmental Protection Agency.

ACTION: Notice; request for public comment.

SUMMARY: In accordance with section 122(i) of the Comprehensive Environmental Response, Compensation, and Liability Act, as amended by the Superfund Amendments and Reauthorization Act ("CERCLA"), notice is hereby given that a proposed administrative cost recovery settlement concerning the Route 52 Site in Bluefield, West Virginia was issued by the Agency on September 24, 1992. The settlement resolves an EPA claim under Section 107 of CERCLA against Joy Technologies Inc. The settlement requires Joy Technologies Inc. to pay $200,000.000 to the Hazardous Substances Superfund.

For thirty (30) days following the date of publication of this notice, the Agency will receive written comments relating to the settlement. The Agency's response to any comments received will be available for public inspection at the U.S. Environmental Protection Agency, Region III, Regional Docket Clerk (3RC00), 841 Chestnut Building, Philadelphia, PA, 19107.

DATES: Comments must be submitted on or before February 10, 1993.

ADDRESSES: The proposed settlement and additional background information relating to the settlement are available for public inspection at U.S. EPA, Region III, 841 Chestnut Building, Philadelphia, PA, 19107. A copy of the proposed settlement may be obtained from Suzanne Canning (3RC00), Regional Docket Clerk, U.S. EPA, Region III, 841 Chestnut Building, Philadelphia, PA, 19107. Comments should reference the Route 52 Site, Bluefield, WVA and EPA Docket No. III–92–09–DC, and should be addressed to Suzanne Canning (3RC00), Regional Docket Clerk, at the above address.

FOR FURTHER INFORMATION CONTACT: Heather Torres (3RC21), Associate Regional Counsel, U.S. EPA, Region III, 841 Chestnut Building, Philadelphia, PA, 19107, (215) 597–0376.

December 10, 1992.

Alvin R. Morris,

Acting Regional Administrator, United States Environmental Protection Agency, Region III.

[FR Doc. 93–528 Filed 1–8–93; 8:45 am]

BILLING CODE 6560–50–M

ENVIRONMENTAL PROTECTION AGENCY

DEPARTMENT OF DEFENSE

Army Corps of Engineers

[FRL–4553–9]

Basis for the Advanced Identification of Wetlands in New Jersey's Hackensack Meadowlands

AGENCY: United States Environmental Protection Agency, United States Army Corps of Engineers, DOD.

ACTION: Notice of completion.

SUMMARY: The United States Environmental Protection Agency (EPA), Region II office, and the United States Army Corps of Engineers (USACE), New York District office, have completed the "Basis for the Advanced Identification of Wetlands in New Jersey's Hackensack Meadowlands". The report may be acquired at the EPA Region II office, 26 Federal Plaza, New York, New York, or the Hackensack Meadowlands Development Commission offices, One DeKorte Park Plaza, Lyndhurst, New Jersey; or may be received upon request to EPA Region II, Marine and Wetlands Protection Branch, 26 Federal Plaza, New York, NY 10278, (212) 264–5170.

FOR FURTHER INFORMATION CONTACT: Mr. Mario Del Vicario, Chief, Marine and Wetlands Protection Branch, U.S. Environmental Protection Agency Region II, 26 Federal Plaza, New York, NY 10278, (212) 264–5170.

SUPPLEMENTARY INFORMATION: The New Jersey Department of Environmental Protection and Energy (NJDEPE), Bureau of Revenue, Maps and Publications Section will serve as a repository for the "Basis for the Advanced Identification of Wetlands in New Jersey's Hackensack Meadowlands". Copies are available for purchase by contacting NJDEPE, Bureau of Revenue, Maps and Publications Section, CN 402, Trenton, New Jersey 08625, (609) 777–1038 or 1039. The cost is $2.00 per figure and approximately $1.25 for the text. Pre-payment to the Treasurer, State of New Jersey, Bureau of Revenue, CN 402, Trenton, NJ 08625 is required.

For the Environmental Protection Agency.

Dated: December 7, 1992.

Constantine Sidamon-Eristoff,

Regional Administrator.

For the Army Corps of Engineers.

Dated: December 9, 1992.

Thomas A. York,

District Engineer.

[FR Doc. 93–533 Filed 1–8–93; 8:45 am]

BILLING CODE 6560–50–M

FEDERAL MARITIME COMMISSION

Ocean Freight Forwarder License; Reissuance

Notice is hereby given that the following ocean freight forwarder license has been reissued by the Federal Maritime Commission pursuant to section 19 of the Shipping Act of 1984 (46 U.S.C. app. 1718) and the regulations of the Commission pertaining to the licensing of ocean freight forwarders, 46 CFR Part 510.

License No.	Name/address	Date reissued
2477–R	MDR Enterprises, Inc., 7377 Pacific Street, #219, Omaha, NE 68114.	October 21, 1992.

Bryant L. VanBrakle,

Director, Bureau of Tariffs, Certification and Licensing.

[FR Doc. 93–491 Filed 1–8–93; 8:45 am]

BILLING CODE 6730–01–M

Ocean Freight Forwarder License; Revocations

Notice is hereby given that the following ocean freight forwarder licenses have been revoked by the Federal Maritime Commission pursuant to section 19 of the Shipping Act of 1984 (46 U.S.C. app. 1718) and the regulations of the Commission pertaining to the licensing of ocean freight forwarders, 46 CFR part 510.

License No:	311.
Name:	John V. Carr & Son, Ltd.
Address:	1600 West Lafayette, Detroit, MI 48216.
Date Revoked:	September 1, 1992.
Reason:	Surrendered license voluntarily.
License Number:	2269.
Name:	Customs Clearance & Dispatch, Inc.
Address:	6300 NW 74th Ave., Miami, FL 33166.
Date Revoked:	September 19, 1992.
Reason:	Failed to furnish a valid surety bond.
License Number:	2706.
Name:	B.V.T. America, Inc.
Address:	55 Armstrong Road, Des Moines, IL 60018.
Date Revoked:	November 12, 1992.
Reason:	Surrendered license voluntarily.
License Number:	266.
Name:	E.A. Jasper, Inc.
Address:	711 Brush Ave., Bronx, NY 10465.
Date Revoked:	December 2, 1992.
Reason:	Failed to furnish a valid surety bond.
License Number:	3481.
Name:	Jinco, Inc.
Address:	1101 Ellis Drive, Bensenville, IL 60106.
Date Revoked:	December 2, 1992.
Reason:	Failed to furnish a valid surety bond.
License Number:	2493–R.
Name:	Universal Transportation Systems, Ltd.
Address:	1695 Woodward, Ste. 200, Bloomfield Hills, MI 48302.
Date Revoked:	December 3, 1992.
Reason:	Surrendered license voluntarily.
License Number:	1309.
Name:	Taub & Carmel, Inc.
Address:	33 Rector Street, New York, NY 10006.
Date Revoked:	December 9, 1992.
Reason:	Failed to furnish a valid surety bond.
License Number:	2238.
Name:	Genuine International Freight Forwarders, Inc.
Address:	183 Milkweed Ct., Three Bridges, NJ 08887.
Date Revoked:	December 12, 1992.
Reason:	Failed to furnish a valid surety bond.
License Number:	3547.
Name:	BMA International Traders and Forwarders. Inc.
Address:	250 South Maple Ave., #B, So. San Francisco, CA 94080.
Date Revoked:	December 20, 1992.
Reason:	Failed to furnish a valid surety bond.

Bryant L. VanBrakle,

Director, Bureau of Tariffs, Certification and Licensing.

[FR Doc. 93–490 Filed 1–8–93; 8:45 am]

BILLING CODE 6730–01–M

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

Availability of Proposed Aquatic Nuisance Species Program

AGENCY: U.S. Fish and Wildlife Service, Interior.

ACTION: Notice of extension of comment period.

SUMMARY: The due date for comments on the proposed Aquatic Nuisance Species Program (Program) and draft environmental assessment is extended to February 3, 1993. The notice announcing the availability of these documents was published on November 18, 1992 (57 FR 54408).

DATES: Comments must be submitted to the address in **ADDRESSES** by February 3, 1993.

ADDRESSES: Requests for copies of and comments about the proposed Aquatic Nuisance Species Program or draft environmental assessment should be sent to Robert A. Peoples, U.S. Fish and Wildlife Service (820 ARLSQ), Department of the Interior, 1849 C Street, NW., Washington, DC 20240.

FOR FURTHER INFORMATION CONTACT: Robert A. Peoples at (703) 358–1718.

SUPPLEMENTARY INFORMATION: The proposed Program was prepared by the Aquatic Nuisance Species Task Force in accordance with section 1202 of the Nonindigenous Aquatic Nuisance Prevention and Control Act of 1990 (Pub. L. 101–646, 16 U.S.C. 4701 *et seq.*). Comments received will be considered in completing the final Program that will become the basis for Federal participation in cooperative responses to aquatic nuisance species.

The November 18, 1992, notice and the six public meetings announced at that time and held in December 1992 have generated substantial interest in the proposed Program among diverse interests. To provide adequate time for interested parties to review and comment on the proposed Program, the comment period is extended 30 days to February 3, 1993.

Dated: January 4, 1993.

Gary Edwards,

Co-Chair, Aquatic Nuisance Species Task Force.

[FR Doc. 93–494 Filed 1–8–93; 8:45 am]

BILLING CODE 4310–55–M

INTERNATIONAL TRADE COMMISSION

[Investigations Nos. 731–TA–632–635 (Preliminary)]

Certain Cordage Products From Costa Rica, Korea, Mexico, and Portugal; Withdrawal of Petition in Antidumping Investigations

AGENCY: International Trade Commission.

ACTION: Notice of withdrawal of petition in antidumping investigations.

SUMMARY: On January 4, 1993, the U.S. Department of Commerce and the U.S. International Trade Commission received a letter from petitioner in the subject investigations (the Cordage Institute, Hingham, MA) withdrawing its petition. Commerce has not initiated investigations as provided in section 732(c) of the Tariff Act of 1930 (19 U.S.C. 1673a(c)). Accordingly, the

Commission gives notice that its antidumping investigations concerning certain cordage products from Costa Rica, Korea, Mexico, and Portugal (investigations Nos. 731–TA–632–635 (Preliminary)) are discontinued.

EFFECTIVE DATE: January 4, 1993.

FOR FURTHER INFORMATION CONTACT: Robert Carpenter (202–205–3172), Office of Investigations, U.S. International Trade Commission, 500 E Street SW., Washington, DC 20436. Hearing-impaired individuals are advised that information on this matter can be obtained by contacting the Commission's TDD terminal on 202–205–1810. Persons with mobility impairments who will need special assistance in gaining access to the Commission should contact the Office of the Secretary at 202–205–2000.

By order of the Commission.

Issued: January 6, 1993.

Paul R. Bardos,

Acting Secretary.

[FR Doc. 93–492 Filed 1–8–93; 8:45 am]

BILLING CODE 7020–02–M

INTERSTATE COMMERCE COMMISSION

Intent to Engage in Compensated Intercorporate Hauling Operations

This is to provide notice as required by 49 U.S.C. 10524(b)(1) that the named corporations intend to provide or use compensated intercorporate hauling operations as authorized in 49 U.S.C. 10524(b).

A.1. Parent corporation and address of principal office: Kraft General Foods, Inc., Three Lakes Drive, Northfield, IL 60093–2758.

2. Wholly owned subsidiaries which will participate in the operations, and State(s) of incorporation:

a. Tombstone Pizza Corporation, a Delaware corporation.

b. National Dairy Products Corp., a Delaware corporation.

B.1. Parent Corporation: Louis Dreyfus Energy Corp., 10 Westport Road, P.O. Box 810, Wilton, CT 06897–0810.

2. Wholly owned subsidiaries which will participate in the operations, and states of incorporation: Louis Dreyfus Energy Heating Oil Inc., a Delaware corporation and Louis Dreyfus Energy Heating Oil Company of Delaware, a Delaware corporation.

C.1. The parent corporation is Ryder System, Inc. a Florida corporation. Its address is 3600 NW. 82d Avenue, Miami, FL 33166.

2. The names of all wholly owned subsidiaries which will participate in the operations, and the state of incorporation, are as follows:

Aeronautical Improvements Corporation	Florida.
Airplane Things, Inc	Texas.
APS Technical Specialities, Inc	California.
ATE Management & Service Company, Inc	Delaware.
ATE Management of Duluth, Inc	Minnesota.
Automotive Rail Handling, Inc	Michigan.
Aviall Far East, Inc	Florida.
Aviation Sales Company, Inc	Florida.
Aviation Sales Leasing Company, Inc	Florida.
B&C, Inc	Michigan.
Blazer Truck Lines, Inc	Michigan.
F. J. Boutell Driveaway Co., Inc	Michigan.
Cape Area Transportation System, Inc	Massachusetts.
Carrier Support, Inc	Delaware.
Central Virginia Transit Management Company, Inc	Virginia.
Commercial Carriers, Inc	Michigan.
Complete Auto Transit, Inc	Michigan.
Consolidated Convoy Company	Oregon.
Convoy Company	Oregon.
E/H Service Corporation	Wisconsin.
Far East Freight, Inc	Florida.
Fleet Carrier Corporation	New York.
Fleet Carrier Dealers Service, Inc	Michigan.
H.N.S. Management Company, Inc	Connecticut.
Inventory Locator Service, Inc	Tennessee.
Jackson Public Transportation Company, Inc	Mississippi.
Janesville Auto Transport Company	Delaware.
M&G Convoy, Inc	New York.
Managed Logistics System, Inc	Delaware.
Merrimack Valley Area Transportation Co., Corp	Massachusetts.
Metro Service Corp	Wisconsin.
Mid-South Transportation Management, Inc	Tennessee.
Murry Recon, Inc	New York.
National Trucking Company	Delaware.
Network Sales, Inc	Tennessee.
Network Vehicle Central, Inc	Florida.
9755 S.W. 67 Avenue, Inc	Florida.
Old Dominion Transit Management Company	Virginia.
OSHCO, Inc	Florida.
Parking Management of Southwest Virginia, Inc	Virginia.
Port Terminal Transport, Inc	California.
QAT, Inc	Florida.
RMX, Inc	Delaware.
RSI Acquisition Corp	Delaware.
RSI Aviation, Inc	Florida.
RSI Purchase Corp	Delaware.

Ryder Airline, Inc	Delaware.
Ryder Airline Services, Inc	Delaware.
Ryder Automotive Carrier Group, Inc	Florida.
Ryder Automotive Operations, Inc	Florida.
Ryder Aviall, Inc	Florida.
Ryder Aviation Sales International, Inc	Florida.
Ryder Capital Corp., Inc	Florida.
RYDERCORP	Florida.
RYDERCORP, Inc	Delaware.
Ryder Dedicated Capacity, Inc	Tennessee.
Ryder Distribution Resources, Inc	Delaware.
Ryder Driver Leasing, Inc	Florida.
Ryder Energy Distribution Corporation	Florida.
Ryder Equity, Inc	Nevada.
Ryder Finance, Inc	Florida.
Ryder Freight Broker, Inc	Virginia.
Ryder Move Management, Inc	Oregon.
Ryder Realty, Inc	Delaware.
Ryder Relocation Services, Inc	Florida.
Ryder Services Corporation	Florida.
Ryder St. Louis Redevelopment Corporation	Missouri.
Ryder Student Assistance Fund, Inc	Rhode Island.
Ryder Student Transportation Services, Inc	Florida.
Ryder Support, Inc	Florida.
Ryder Truck Rental, Inc	Florida.
Ryder Truck Rental—One Way, Inc	Delaware.
Ryder Truckstops, Inc	Florida.
South Florida Mortgage Group, Inc	Florida.
Southwestern Virginia Transit Management Co., Inc	Virginia.
Summit Industries, Inc	Delaware.
Terminal Service Co	Washington.
Transit Contractors, Inc	California.
Transit Management Company of Laredo	Texas.
Transit Management of Alexandria, Inc	Virginia.
Transit Management of Charlotte, Inc	North Carolina.
Transit Management of Connecticut, Inc	Connecticut.
Transit Management of Danville, Inc	Illinois.
Transit Management of Decatur, Inc	Illinois.
Transit Management of Durham, Inc	North Carolina.
Transit Management of Great Falls, Inc	Montana.
Transit Management of Hamilton, Inc	Ohio.
Transit Management of Jamestown, Inc	New York.
Transit Management of Monroe County, Inc	Michigan.
Transit Management of St. Joseph, Inc	Missouri.
Transit Management of Spartanburg, Inc	South Carolina.
Transit Management of Tucson, Inc	Arizona.
Transit Management of Washoe, Inc	Nevada.
Transit Management of Waukesha, Inc	Wisconsin.
Transport Support, Inc	Delaware.
Transportation Management of Tennessee, Inc	Tennessee.
Westside Corporate Center, Inc	Florida.

Sidney L. Strickland, Jr.,

Secretary.

[FR Doc. 93–489 Filed 1–8–93; 8:45 am]

BILLING CODE 7035-01-M

[No. 40888]

Reconsideration of Special Tariff Authorities Authorizing the Publication of Customer Account Codes in Tariffs

AGENCY: Interstate Commerce Commission.

ACTION: Notice of proposal to reconsider outstanding Special Tariff Authorities.

SUMMARY: The Commission plans to reconsider all outstanding Special Tariff Authorities that allow carriers to publish tariff rates for shippers identified only through the means of account codes listed in the tariffs. Questions have been raised regarding whether the publication of rates in this manner complies with the rate disclosure requirements of the Interstate Commerce Act, and Congress has requested the Commission to initiate a proceeding to reconsider the matter. After consideration of the comments received and the issues involved, the Commission expects to determine whether the Special Tariff Authorities should be continued, modified or revoked.

DATES: Comments are due on March 8, 1993.

ADDRESSES: Send comments (an original and 10 copies) referring to Docket No. 40888 to: Interstate Commerce Commission, Office of the Secretary, Case Control Branch, Washington, DC 20423.

FOR FURTHER INFORMATION CONTACT: James W. Greene (202) 927–5597, or Ronald A. Hall (202) 927–5595, [TDD for hearing impaired (202) 927–5721].

SUPPLEMENTARY INFORMATION: On January 30, 1985, the Commission approved a motor carrier's request to restrict the application of tariff rates to specific customers by the use of unique customer code numbers.[1] The reason advanced by the carrier in support of its request was primarily to facilitate the computerization of rating and billing processes. Subsequently, numerous similar authorizations were granted to other motor and water carriers, and, on

[1] Special Tariff Authority No. 84–9406.

April 29, 1986, the Commission's Suspension/Special Permission Board, acting on its own motion, granted a Special Tariff Authority [2] which allowed all motor carriers and freight forwarders to make use of shipper account codes in tariffs filed by them or on their behalf. (A complete listing of all outstanding Special Tariff Authorities allowing the publication of shipper codes is contained in appendix A.)

The Commission again addressed the issue of customer account codes in Pet. for Declar. Order-Discounts and Customer Acct. Codes, 8 I.C.C.2d 47 (1991). In that proceeding, the Commission declined to find customer account code tariffs unlawful, per se, but indicated its willingness to consider such tariffs on a case-by-case basis. As the Commission there stated (8 I.C.C.2d at 54):

> If a tariff lacks any of the essential information concerning the commodities, service points, and rate information, it is not the use of a customer code that would invalidate the tariff. Conversely, mere use of shipper codes does not mean necessarily that the tariff lacks any necessary information. [footnote omitted]

Based on Congress' request that we do so,[3] we are instituting this proceeding to reconsider whether the Special Tariff Authorities that allow carriers to publish tariff rates for shippers identified only through the means of account codes should be continued, modified, or revoked.

Comments are invited from interested parties regarding the lawfulness of publishing rates through the use of shipper account codes that are not explained in the rates tariff or in a governing tariff. Comments are also invited as to whether the Commission should continue or revoke the existing Special Tariff Authorities, the likely impact of such action, and any modifications the Commission should consider with respect to such Authorities. We are well aware that shipper codes may be used in connection with other methods of tariff publication which are alleged to fail the disclosure requirements such as the range and trigger tariff provisions being considered in Docket Nom. 40887, Range Tariffs of All Motor Common Carriers—Show Cause Proceeding, show cause order served concurrently with the notice here. Parties are requested to limit their comments in this proceeding to the question of whether a tariff that in all other respects satisfies disclosure requirements should be deemed to be invalid simply because it is published utilizing undisclosed shipper codes.

Decided: December 23, 1992.

By the Commission, Chairman Philbin, Vice Chairman McDonald, Commissioners Simmons and Phillips.

Sidney L. Strickland, Jr.,

Secretary.

Outstanding Special Tariff Authorities Authorizing the Publication of Customer Account Codes in Tariffs

84–0406	85–2105
85–144	85–2106
85–547	85–2107
85–1455	85–2108
85–1507	85–2115
85–1508	85–2125
85–1594	85–2132
85–1619	85–2136
85–1620	85–2155
85–1648	85–2156
85–1665	85–2160
85–1666	85–2164
85–1668	85–2192
85–1671	85–2195
85–1672	85–2196
85–1677	85–2206
85–1683	85–2209
85–1695	85–2232
85–1703	85–2257
85–1715	85–2261
85–1725	85–2264
85–1730	85–2275
85–1731	85–2282
85–1773	85–2318
85–1777	85–2344
85–1779	85–2345
85–1780	85–2350
85–1805	85–2352
85–1808	85–2353
85–1809	85–2358
85–1823	85–2362
85–1834	85–2398
85–1857	85–2399
85–1860	85–2413
85–1866	85–2424
85–1873	85–2429
85–1876	85–2438
85–1879	85–2439
85–1888	85–2458
85–1895	85–2460
85–1927	85–2461
85–1928	85–2488
85–1929	85–2509
85–1935	85–2538
85–1937	85–2544
85–1943	85–2576
85–1952	85–2577
85–1957	85–2578
85–1960	85–2600
85–1969	85–2663
85–1986	85–2690
85–1988	85–2715
85–1989	86–1
85–1990	86–35
85–2004	86–41
85–2016	86–48
85–2033	86–78
85–2039	86–129
85–2040	86–132
85–2042	86–152
85–2047	86–155
85–2056	86–195
85–2067	86–247
85–2093	86–265
85–2103	86–275
85–2104	86–294
85–314	86–531
85–316	86–535
85–325	86–547
85–340	86–556
86–344	86–563
86–351	86–591
86–398	86–603
86–404	86–607
86–440	86–638
86–448	86–639
86–470	87–198
86–479	88–26
86–482	88–43
86–483	88–48
86–487	88–60
86–492	89–30

[FR Doc. 93–487 Filed 1–8–93; 8:45 am]

BILLING CODE 7035–01–M

[2] Special Tariff Authority 86–639, amended April 29, 1986, to provide for numerical and/or alphabetical codes.

[3] Senate Report No. 102–351, dated July 30, 1992, and accompanying the U.S. Department of Transportation and Related Agencies Appropriations Bill, 1993.

[No. 40887]

Range Tariffs of All Motor Common Carriers—Show Cause Proceeding

In Docket Nos. 40843 ("Ranges of Rates") [1] and ("Ranges of Discounts") [2] we ordered certain tariff publishing agents and motor common carriers to show cause why we should not order particular "range" tariffs canceled for failure to comply with the rate disclosure requirements of 49 U.S.C. 10762. We are now requiring all publishers and motor common carrier users of range tariffs likewise to demonstrate why their tariffs should not be ordered canceled. Because the proceeding will be of interest to many shippers, we are also inviting the public to comment. A consolidated decision will then be issued for the three proceedings.

We decided to institute this industry-wide proceeding principally [3] because the comments received in the two pending show cause proceedings do not persuade us at this point that the range tariffs which they address meet the disclosure requirements of the Interstate Commerce Act (Act). Range tariffs are clearly useful to certain segments of the

[1] Docket No. 40843, Tariffs of Certain Motor Common Carriers Containing "Ranges of Rates"—Show Cause Proceeding (not printed), show cause order served August 20, 1992.

[2] Docket No. 40848, Tariffs of Certain Motor Common Carriers Containing "Ranges of Discounts"—Show Cause Proceeding (not printed), served September 8, 1992.

[3] A second consideration was that a number of comments state that almost all motor common carriers now use similar range tariffs, and that it is unfair and ineffectual to single out individual, mostly small carriers for show cause proceedings. We agree. Third, the Senate Committee on Appropriations has instructed us "to initiate, as soon as possible, an industrywide proceeding to eliminate motor tariff filings that fail to explicitly state actual rates applied by carriers or that use so-called 'range' or 'write-in' provisions." *See* Senate Report No. 102–351, dated July 30, 1992, and accompanying the U.S. Department of Transportation and Related Agencies Appropriations Bill, 1993.

industry and may also further certain goals of the national transportation policy. However, Congress has not repealed the rate-filing requirement or the antidiscrimination requirement [4] of the Act. Therefore, our primary focus must be on whether such tariffs disclose their rates sufficiently to satisfy the mandates of sections 10761(a) and 10762, as elucidated in *Regular Common Carrier Conference* v. *United States*, 793 F.2d 376 (D.C. Cir. 1986). Comments are requested to address this issue in particular.

Additional information is contained in the Commission's decision. To obtain a copy of the full decision, write to, call, or pick up in person from: Office of the Secretary, room 2215, Interstate Commerce Commission, Washington, DC 20423. Telephone: (202) 927–7428. [Assistance for the hearing impaired is available through TDD services (202) 927–5721.]

Comments are due March 8, 1993. Send comments (an original and 10 copies) referring to Docket No. 40887 to: Interstate Commerce Commission, Office of the Secretary, Case Control Branch, Washington, DC 20423.

Decided: December 23, 1992.

By the Commission, Chairman Philbin, Vice Chairman McDonald, Commissioners Simmons and Phillips.

Sidney L. Strickland, Jr.,

Secretary.

[FR Doc. 93–486 Filed 1–8–93; 8:45 am]

BILLING CODE 7035-01-M

[Docket No. AB–290 (Sub-No. 119X)]

Norfolk and Western Railway Co.; Abandonment Exemption; Delphos, OH

Norfolk and Western Railway Company (NW) has filed a notice of exemption under 49 CFR part 1152 subpart F—Exempt Abandonments to abandon its 0.54-mile line of railroad between mileposts AY–0.00 and AY–0.14 and between AY–1.36 and AY–1.76 at Delphos, OH, in Allen and Putnam Counties, OH.

NW has certified that: (1) No local traffic has moved over the line for at least 2 years; (2) there is no overhead traffic on the line; and (3) no formal complaint filed by a user of rail service on the line (or a State or local government entity acting on behalf of such user) regarding cessation of service over the line either is pending with the Commission or with any U.S. District Court or has been decided in favor of the complainant within the 2-year period. NW also certified that it has complied with the requirements at 49 CFR 1105.7 and 1105.8, 49 CFR 1105.12 (newspaper publication), and 49 CFR 1152.50(d)(1) (notice to government agencies).

As a condition to the use of this exemption, any employee affected by the abandonment shall be protected under Oregon Short Line R. Co.—Abandonment—Goshen, 360 I.C.C. 91 (1979). To address whether this condition adequately protects affected employees, a petition for partial revocation under 49 U.S.C. 10505(d) must be filed.

Provided no formal expressions of intent to file an offer of financial assistance (OFA) has been received, this exemption will be effective on February 10, 1993, unless stayed pending reconsideration. Petitions to stay that do not involve environmental issues,[1] formal expressions of intent to file an OFA under 49 CFR 1152.27(c)(2),[2] and trail use/rail banking statements under 49 CFR 1152.29 must be filed by January 21, 1993.[3] Petitions to reopen or requests for public use conditions under 49 CFR 1152.28 must be filed by February 1, 1993, with: Office of the Secretary, Case Control Branch, Interstate Commerce Commission, Washington, DC 20423.

A copy of any petition filed with the Commission should be sent to applicant's representative: F. Blair Wimbush, Norfolk Southern Corporation, Three Commercial Place, Norfolk, VA 23510–2191.

If the notice of exemption contains false or misleading information, use of the exemption is void *ab initio*.

Applicant has filed an environmental report which addresses the abandonment's effect, if any, on the environmental or historic resources.

The Section of Energy and Environment (SEE) will issue an environmental assessment (EA) by January 16, 1993. Interested persons may obtain a copy of the EA from SEE by writing to it (room 3219, Interstate Commerce Commission, Washington, DC 20423) or by calling Elaine Kaiser, Chief, SEE at (202) 927–6248. Comments on environmental and historic preservation matters must be filed within 15 days after the EA becomes available to the public.

Environmental, historic preservation, public use, or trail use/rail banking conditions will be imposed, where appropriate, in a subsequent decision.

Decided: December 28, 1992.

By the Commission, Julia Farr, Acting Director, Office of Proceedings.

Sidney L. Strickland, Jr.,

Secretary.

[FR Doc. 93–485 Filed 1–8–93; 8:45 am]

BILLING CODE 7035-01-M

[4] 49 U.S.C. 10741; see also the policy expressed in 10101(a)(1)(D) that rates be reasonable and "without unreasonable discrimination".

[1] A stay will be routinely issued by the Commission in those proceedings where an informed decision on environmental issues (whether raised by a party or by the Section of Energy and Environment in its independent investigation) cannot be made prior to the effective date of the notice of exemption. See Exemption of Out-of-Service Rail Lines, 5 I.C.C.2d 377 (1989). Any entity seeking a stay involving environmental concerns is encouraged to file its request as soon as possible in order to permit this Commission to review and act on the request before the effective date of this exemption.

[2] See Exempt. of Rail Abandonment—Offers of Finan. Assist., 4 I.C.C.2d 164 (1987).

[3] The Commission will accept a late-filed trail use statement as long as it retains jurisdiction to do so.

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

Manufacturer of Controlled Substances; Application

Pursuant to § 1301.43(a) of title 21 of the Code of Federal Regulations (CFR), this is notice that on December 1, 1992, Johnson Matthey Inc., Custom Pharmaceuticals Department, 2002 Nolte Drive, West Deptford, New Jersey 08066, requested by application to the Drug Enforcement Administration (DEA) for registration as a bulk manufacturer of the basic classes of controlled substances listed below:

Drug	Schedule
Methylphenidate (1724)	II
Alfentanil (9737)	II
Sufentanil (9740)	II
Fentanyl (9801)	II

Any other such applicant and any person who is presently registered with DEA to manufacture such substances may file comments or objections to the issuance of the above application and may also file a written request for a hearing thereon in accordance with 21 CFR 1301.54 and in the form prescribed by 21 CFR 1316.47.

Any such comments, objections, or requests for a hearing may be addressed to the Deputy Assistant Administrator, Office of Diversion Control, Drug Enforcement Administration, United States Department of Justice, Washington, DC 20537, Attention: DEA Federal Register Representative (CCR), and must be filed no later than 30 days from publication.

Dated: December 28, 1992.

Gene R. Haislip,

Deputy Assistant Administrator, Office of Diversion Control, Drug Enforcement Administration.

[FR Doc. 93–493 Filed 1–8–93; 8:45 am]

BILLING CODE 4410–09–M

Office of Justice Programs; Office for Victims of Crime

Children's Justice Act Discretionary Grant Program for Native Americans and Application Kit for Fiscal Year 1993

AGENCY: Office of Justice Programs, Office for Victims of Crime, Justice.

ACTION: Public announcement of the availability of Fiscal Year 1993 grant funds and Application Kit for the Children's Justice Act Discretionary Grant Program for Native Americans.

SUMMARY: The Office for Victims of Crime (OVC) is publishing this announcement of the availability of Fiscal Year 1993 grant funds and the Application Kit for the Children's Justice Act Grant Program for Native Americans (CJA). The purpose of this grant program is to develop model projects in Native American communities for the purpose of improving the investigation, prosecution and handling of cases of child sexual abuse and serious child physical abuse in a manner that increases support for and reduces trauma to child victims.

DATES: The Application Kit specifies the due date for applications. All applications responding to the announcement must be received by OVC by the close of business on the specified due date indicated in the Application Kit. Applications received after the deadline will not be considered.

ADDRESSES: Office for Victims of Crime, Federal Crime Victims Division, 633 Indiana Avenue, NW., Washington, DC 20531.

FOR FURTHER INFORMATION CONTACT: Cathy Sanders or Bill Brantley, Federal Crime Victims Division, Office for Victims of Crime, at the above address. Telephone (202) 514-6445 for further information and to obtain a copy of the Application Kit.

SUPPLEMENTARY INFORMATION: Pursuant to section 1402(g) of the Victims of Crime Act (VOCA) of 1984, Public Law 98–473, as amended, 42 U.S.C. 10601(g), the Attorney General, acting through the Director of OVC, is authorized to make grants for the purpose of assisting Indian tribes in developing, establishing and operating programs designed to improve the handling, investigation and prosecution of child abuse cases, especially child sexual abuse cases.

The goal of this program is to strengthen existing Native American CJA programs and/or develop new programs that improve the handling of child physical and sexual abuse cases during the investigation, prosecution, and treatment phases. The objectives are to make systemic improvements and to develop effective programs that address serious child abuse cases. Once projects are in place, they will serve as models for other tribes seeking to make similar improvements. Each program must address coordination with Federal and State authorities as well as coordination within the tribe.

The program focuses on handling serious cases of child abuse that would be handled in criminal court from the initial report and the first stages of intervention and investigation through the resolution of the case, in a manner that increases support for the child victim and lessens the trauma. Desired results are improved investigative and prosecutorial practices, better case coordination, and improved services for child victims and their families.

The Office for Victims of Crime published a Notice in the **Federal Register** (57 FR 52639, November 4, 1992) announcing the FY 1993 Discretionary Program Plan. The Grant Application Kit for the Children's Justice Act Discretionary Grant Program for Native Americans expands upon information provided in the program plan and defines specific application requirements and deadlines.

John E. Dawson,

Acting Deputy Director, Office for Victims of Crime.

Olga R. Trujillo,

Acting General Counsel.

[FR Doc. 93–442 Filed 1–8–93; 8:45 am]

BILLING CODE 4410–18–M

DEPARTMENT OF LABOR

Labor Advisory Committee for Trade Negotiations and Trade Policy; Meeting

Pursuant to the provisions of the Federal Advisory Committee Act (Pub. L. 92–463 as amended), notice is hereby given of a meeting of the Labor Advisory Committee for Trade Negotiations and Trade Policy.

Date, time and place: February 10, 1993, 10 am–12 noon, Rm. S–4215 A&B, Department of Labor Building, 200 Constitution Ave., NW., Washington, DC 20210.

Purpose: to discuss trade negotiations and trade policy of the United States.

This meeting will be closed under the authority of section 10(d) of the Federal Advisory Committee Act and 5 U.S.C. 552(c)(1). The Committee will hear and discuss sensitive and confidential matters concerning U.S. trade negotiations and trade policy.

For further information, contact: Fernand Lavallee, Director, Trade Advisory Group, Phone: (202) 523–2752.

Signed at Washington, DC, this 6th day of January, 1993.

Shellyn G. McCaffrey,

Deputy Under Secretary International Affairs.

[FR Doc. 93–535 Filed 1–8–93; 8:45 am]

BILLING CODE 4510–28–M

Pension and Welfare Benefits Administration

[Prohibited Transaction Exemption 93–2; Exemption Application Nos. D–8243 and D–8323]

Class Exemption for the Receipt of Certain Services by Individuals for Whose Benefit Individual Retirement Accounts or Retirement Plans for Self-Employed Individuals Have Been Established or Maintained

AGENCY: Pension and Welfare Benefits Administration, U.S. Department of Labor.

ACTION: Grant of class exemption.

SUMMARY: This document contains a final exemption from certain prohibited transaction restrictions of the Internal Revenue Code of 1986 (the Code). The exemption permits the receipt of services at reduced or no cost by an individual for whose benefit an individual retirement account (IRA), or, if self-employed, a Keogh Plan, is established or maintained, or by members of his or her family, from a bank, provided the conditions of the exemption are met. The exemption affects certain individuals with a beneficial interest in the IRAs or Keogh Plans who receive such services, as well as the banks that provide the services.

EFFECTIVE DATE: May 11, 1993.

FOR FURTHER INFORMATION CONTACT: Allison K. Padams, Office of Exemption Determinations, Pension and Welfare Benefits Administration, U.S. Department of Labor, (202) 523–8971 (this is not a toll-free number); or Susan E. Rees, Plan Benefits Security Division, Office of the Solicitor, U.S. Department of Labor, (202) 523–9141 (this is not a toll-free number).

SUPPLEMENTARY INFORMATION: On February 28, 1991, the Department of

Labor (the Department) published a notice in the **Federal Register** (56 FR 8365) of the pendency of a proposed class exemption from the sanctions resulting from the application of sections 4975(a) and (b), 4975(c)(3) and 408(e)(2) of the Code by reason of section 4975(c)(1)(D), (E) and (F) of the Code.[1] The Department proposed the class exemption in response to applications filed on behalf of the American Bankers Association (the ABA) on November 14, 1989 and the Consumer Bankers Association on February 20, 1990. The applications were filed under section 4975(c)(2) of the Code, and in accordance with the procedure set forth in ERISA Procedure 75–1 (40 FR 18471, April 28, 1975).

The notice of pendency gave interested persons an opportunity to comment on the proposal. Twenty-three public comments were received pursuant to the provisions of section 4975(c)(2) of the Code and in accordance with the procedures set forth in ERISA Procedure 75–1. Upon consideration of all the comments received, the Department has determined to grant the proposed class exemption subject to certain modifications. These modifications and the major comments are discussed below.

Discussion of Comments Received

1. Scope

The proposed exemption limited relief to transactions involving IRAs and Keogh Plans which are not "employee benefit plans" covered by title I of ERISA.[2] The ABA and a number of other commenters urged the Department to expand the exemption to provide relief for transactions involving simplified employee pensions (SEPs) as defined under section 408(k) of the Code. According to the comments, SEP arrangements are, for all practical purposes, no different than other IRAs covered by the proposed exemption. On the basis of the comments received, the Department has decided that it may be appropriate to provide administrative relief from sections 406(a)(1)(D) and 406(b) of the Employee Retirement Income Security Act of 1974 (ERISA) for transactions involving SEPs.

However, the Department did not propose relief from section 406(b) of ERISA at the time the class exemption was proposed, and pursuant to the requirements of section 408(a) of ERISA, the Department is required to offer interested persons an opportunity to present their views and an opportunity for a hearing before granting an exemption from section 406(b). Therefore, in order not to delay the exemption from section 4975(c)(1) (D), (E) and (F) of the Code for transactions involving IRA and Keogh Plans not covered by title I of ERISA, the Department has decided to grant the exemption described herein, and to simultaneously publish elsewhere in this issue of the **Federal Register**, a notice of proposed class exemption from sections 406(a)(1)(D) and 406(b) of ERISA for transactions involving the receipt of services at reduced or no cost by a participant covered under a SEP.

Other commenters requested that relief be extended to include all IRAs and Keogh Plans covered by title I of ERISA. As noted above, the extension of relief to all title I IRAs and Keogh Plans is beyond the scope of this proceeding. Moreover, the Department does not agree that, on the basis of current information, an exemption should be proposed to extend relief to IRAs and Keogh Plans covered by title I other than SEPs. Accordingly, the Department has not made the requested modification.

Finally, the ABA urged the Department to modify the final exemption to provide relief from all of section 4975(c)(1) of the Code in order to avoid uncertainty as to the scope and effect of the exemption. The Department is not persuaded that additional relief is necessary for the transactions covered by the exemption. Consequently, the exemption has not been revised in this regard.

2. Conditions

Section II(b) of the proposed exemption conditioned relief on the services being of the type which the bank itself could offer consistent with applicable federal and state banking law. Two commenters suggested that the Department modify this condition to permit banks to offer services provided by affiliates of the bank which are not of the type that the bank itself could provide to customers directly (e.g., brokerage services). Other commenters requested that the Department broaden section II(b) to include services provided by third parties. The Department is not persuaded by the commenters that such an expansion of the exemption would be appropriate. The Department, however, recognizes that banks typically contract with third parties to provide customers with products of a de minimis value such as checkbooks which are directly related to the provision of customary banking services. The Department believes that the provision of such incidental products is consistent with the safeguards embodied in the exemption. To clarify this matter, the final exemption includes a new section III(g) which defines the term "services".

Under section II(c) of the proposed exemption, the services were required to be provided by the bank in the ordinary course of the bank's business to customers who do not qualify for reduced or no cost banking services. Two commenters urged the Department to modify section II(c) to allow banks to offer some services exclusively to relationship banking customers (e.g., consolidated account summaries or special teller lines). The commenters noted that these banking services are part of established and legitimate business practices. The Department finds merit in these comments. However, the Department believes that the limitation on relationship banking services to services that the bank provides to relationship banking customers who do not maintain IRAs or Keogh Plans with the bank is an important safeguard under the exemption. Accordingly, section II(c) has been revised to require that the reduced or no cost banking services must be offered by the bank to customers other than those who qualify for such services by reason of IRAs and Keogh Plans maintained with the bank. In this regard, the Department notes that this condition would preclude the provision of services that specifically relate to the establishment or maintenance of IRAs or Keogh Plans.

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[1] Section 102 of Reorganization Plan No. 4 of 1978 (43 FR 47713, October 17, 1978) generally transferred the authority of the Secretary of the Treasury to issue administrative exemptions under section 4975(c)(2) of the Code to the Secretary of Labor.

[2] 29 CFR 2510.3–2(d) explains that IRAs described in section 408(a) of the Code will not be considered pension plans subject to title I of ERISA, provided that: (1) No contributions to the plan are made by the employer or employee association; (2) participation is completely voluntary for employees or members; (3) the sole involvement of the employer or employee organization is without endorsement to permit the sponsor to publicize the program, to collect contributions on behalf of the sponsor through payroll deductions or dues checkoffs and to remit them to the sponsor; and (4) the employer or employee organization receives no consideration in the form of cash or otherwise other than reasonable compensation for services actually rendered in connection with payroll deductions or dues checkoffs.

29 CFR 2510.3–3(b) explains that for purposes of title I of ERISA, "employee benefit plan" shall not include a Keogh Plan under which no employees are covered under the plan. In this regard, 29 CFR 2510.3–3(c) states that for purposes of the above referenced section: (1) An individual and his or her spouse shall not be deemed to be employees with respect to a trade or business, whether incorporated or unincorporated, which is wholly owned by the individual and his or her spouse; and (2) a partner in a partnership and his or her spouse shall not be deemed to be employees with respect to the partnership.

Another commenter requested that the final exemption clarify that services provided in the ordinary course of an affiliate's business are also covered by the exemption. The Department wishes to note that relief is available under the exemption for services provided by an affiliate of the bank if such services are of the type that the bank itself could offer consistent with applicable banking law and are offered by the bank on a regular basis to customers who do not maintain IRAs and Keogh Plans with the bank. To the extent that the commenter is requesting additional relief, the Department does not believe that it is appropriate to further revise this condition.

Section II(d) of the proposal required that, for the purpose of determining eligibility to receive services at reduced or no cost, the deposit balance in the IRA or Keogh Plan be treated in the same manner as account balances of the same dollar amount, other than those in IRAs or Keogh Plans, which are maintained by customers of the bank. A number of commenters suggested that this condition was inconsistent with the current practice of the banking industry because the economics of banking require price discrimination by account type. The commenters urged the Department to modify this condition to permit banks to establish different minimum balances for each type of account according to the bank's own rate of return earned on each type of account. The Department recognizes that the exemption as proposed may be inconsistent with the existing practices of some banks, and, therefore, may discourage banks from including IRA and Keogh Plans in their relationship banking programs. However, the Department is concerned that a relationship banking program which establishes a different dollar threshold amount for each type of account in order to qualify for reduced or no cost services could have an adverse impact on IRA and Keogh Plan investments. In light of this concern, but in recognition that many financial institutions do not treat all banking balances as fungible, the Department has determined to revise section II(d) to provide that a relationship banking program would comply with this condition if the deposit balance requirement for IRAs and Keogh Plans is equal to the lowest balance required for any type of account which is counted by the bank in determining eligibility to receive reduced or no cost services. For example, if a bank establishes a relationship banking program under which a customer will be eligible for reduced or no cost services if he maintains a savings account balance of $1,000 or a Certificate of Deposit (CDs) balance of $5,000, section II(d) would be satisfied if the minimum balance required for IRAs or Keogh Plans to receive services under this program is $1,000 regardless of whether a savings account or CD investment is selected for the IRA or Keogh Plan.

In this regard, the Department notes that relief would not be available under the exemption for programs that determine eligibility on the basis of an aggregate balance of different types of account balances, unless the dollar amount of the IRA or Keogh Plan balance is weighted in the same manner as the dollar amount in the type of account with the lowest minimum balance eligible to participate in the program. For example, section II(d) will not be satisfied if a bank offers a package of services under a program which: (1) Requires customers to maintain an aggregate balance of $10,000 or more; (2) counts only those accounts with a minimum balance of $1000; and (3) counts, for purposes of aggregation, CDs and checking account balances on a dollar for dollar basis, and passbook accounts, IRAs and Keogh Plans on the basis of 50 cents for each dollar in such accounts. This type of program does not satisfy section II(d) because the IRA and Keogh Plan balances are not weighted in the same manner as the balances of either CDs or checking accounts.

The Department further notes that, under the rule contained in section II(d), if banks offer different packages of services depending on the amount of the customers' balances, the IRA or Keogh Plan customer must be eligible to receive the same services that non-IRA and non-Keogh Plan customers are eligible to receive under the particular relationship banking package. For example, if a bank establishes a multi-level relationship banking program, under which a Level I customer is eligible for reduced or no cost services if he maintains a savings account balance of $1,000 or a CD balance of $5,000, the minimum balance required under section II(d) for IRAs or Keogh Plans would be $1,000, and the IRA or Keogh Plan customer must be eligible to receive the same Level I services as non-IRA and non-Keogh Plan customers. Similarly, if a Level II customer is eligible to receive additional services if he maintains a savings account balance of $5,000 or a CD balance of $10,000 the minimum balance required for the IRA or Keogh Plan would be $5,000, and the IRA or Keogh Plan customer must be eligible to receive the same Level II services as non-IRA and non-Keogh Plan customers.

The Department also notes that relationship banking programs which treat all banking balances as fungible would continue to satisfy section II(d) as revised.

Under section II(e) of the proposal, the receipt of services would have been covered if the rate of return on the IRA or Keogh Plan investment was no less favorable than the rate of return on an identical investment that could have been made at the same time by a customer of the bank who is not eligible for (or who does not receive) reduced or no cost services. Several commenters urged the Department to delete section II(e). Other commenters requested that the Department clarify that section II(e) only requires that the rate of return earned on an IRA or Keogh Plan investment of a relationship banking customer be identical to that of an IRA or Keogh Plan investment of a non-relationship banking customer. In this regard, the Department wishes to note that section II(e) of the proposal was not limited by its terms to a comparison of IRA and Keogh Plan investments by relationship banking customers with IRA and Keogh Plan investments by non-relationship banking customers. The Department believes that a separate condition which requires that identical investments be offered to non-plan customers assures that the IRAs and Keogh Plans are afforded the same investment opportunities which are available to other customers of the bank who do not receive reduced or no cost services. Therefore, the Department cannot conclude that deletion or modification of this section is warranted.

Two commenters requested that the Department substitute the word "similar" for the word "identical" with respect to this condition. Since the adoption of this suggestion would necessitate a subjective determination, the Department does not believe that it would be appropriate to revise section II(e) in this regard.

Two commenters urged the Department to limit section II(e) to those investments made at the same branch of a bank because banks often offer different rates of return at different branches of the bank according to the market conditions of that geographic area. The Department sees merit in these comments and has limited this section to each branch of the bank.

Finally, in response to several comments, the Department notes that section II(e) does not preclude a bank from offering a more favorable rate of return on an IRA or Keogh Plan

investment which is otherwise identical to an investment available to other customers of such bank, regardless of participation in the relationship banking program.

3. Effective Date

As proposed, the final exemption would be effective as of the date of publication in the Federal Register. The ABA requested that the final exemption provide three types of transitional relief: (1) A delayed effective date of 120 days; (2) the exemption of binding arrangements; and (3) the exemption of binding investments. The ABA stated that banks will need 120 days to make the transition from Announcement 90–1[3] since it contains conditions which are different than those in the proposed exemption. The Department concurs with this comment and believes that a delayed effective date of 120 days is a reasonable period of time for banks to accomplish this transition.[4]

The second type of transitional relief requested is the exemption of binding arrangements involving reduced or no cost services entered into prior to the effective date of the exemption which comply with Announcement 90–1. Lastly, the ABA requested that the Department modify the exemption to permit banks to consider, for relationship banking purposes, binding IRA and Keogh Plan investments made prior to the exemption's effective date that complied with that Announcement. The ABA argued that these arrangements and investments may not meet the conditions of the final exemption, and that banks would be required to disregard them.

The Department is not persuaded by the commenter's argument regarding the provision of additional transitional relief. Under Announcement 90–1, the Service stated that the Announcement would be effective until the Department's final determination regarding the exemption. In this regard, the Department notes that banks were fully aware of the temporary nature of the Announcement, and had the opportunity to develop or alter their relationship banking packages accordingly. In addition, the Department believes that the safeguards contained in the final exemption would be diminished if the exemption were to provide relief for these binding arrangements and investments. Accordingly, the Department believes that a delayed effective date of 120 days adequately addresses the commenter's concerns regarding the need for transitional relief. This effective date provides sufficient time for banks to conform their relationship banking programs and policies to the conditions of the final exemption.

4. Definitions

The term bank is defined under the proposal as a bank described in section 408(n) of the Code. One commenter requested that the Department modify the definition of bank to include institutions which qualify as trustees of IRAs under section 408(a)(2) of the Code. Another commenter urged the Department to include bank affiliates which offer IRAs to customers. In the absence of any showing regarding how the safeguards contained in the exemption would apply to financial institutions described in Code section 408(a)(2) or bank affiliates, the Department is unable to conclude that such modification is warranted.

The proposed exemption defined the term deposit balance as having the same meaning as the term deposits which is contained in section 408(b)(4) of ERISA and defined under 29 CFR 2550.408b–4(c)(3). Thus, deposit balance includes any account upon which a reasonable rate of interest is paid, including a certificate of deposit issued by a bank or similar financial institution. The ABA urged the Department to broaden the definition of deposit balance to encompass all investments made by IRAs and Keogh Plans including those available only to IRAs and Keogh Plans. One of the Department's concerns in developing this exemption was to assure that the rate of return earned on an IRA or Keogh Plan investment is not sacrificed in favor of a customer's receipt of reduced or no cost services. In light of the Department's discussion above regarding the requirement under section II(e) that identical investments be offered to plan and non-plan customers, the Department does not believe that further relief is warranted.

One commenter was concerned about the Department's decision to include brothers, sisters and spouses of brothers or sisters within the definition of "member of his or her family." In this regard, the Department notes that this definition does not preclude a bank from limiting the number of family members entitled to receive relationship banking services under its program. Two other commenters urged the Department to expand this definition to include "domestic partners." The Department has determined not to make this revision because the scope of the term "domestic partners" has not been sufficiently defined.

Miscellaneous

1. Two commenters sought clarification from the Department regarding who is eligible to receive relationship banking services under the exemption. In response to the comments the Department has added language to the exemption to clarify that relief is limited under the exemption to the receipt of services by the individual covered under the IRA or Keogh Plan and his or her beneficiaries who are members of the family within the meaning of section III(f) of the final exemption.

2. Two commenters raised the question whether banks can include services which are available to all customers at no cost in their relationship banking programs. The Department notes that the exemption does not preclude banks from offering free services to customers participating in a relationship banking program.

3. A commenter requested that the Department clarify that, for purposes of the exemption, the term "service" includes the provision of life insurance by a credit union to its members. The Department directs the commenter to the Grant of Class Exemption for Certain Transactions Involving Persons for Whose Benefit an Individual Retirement Account or Retirement Plan for Self-Employed Individuals is Established which the Department is also publishing in today's Federal Register.

4. Certain commenters expressed concern whether banks may include credit based products as a method of qualifying for a bank's relationship banking program. In this regard, the Department notes that the preamble to the proposed exemption, in explaining the application of section II(d), contained an example of a relationship banking program which included loan balances in determining eligibility to receive services at reduced or no cost.[5]

5. In response to one commenter, the Department notes that the exemption does not require banks to include either or both IRAs and Keogh Plans in their relationship banking programs.

[3] The Service issued a nonenforcement policy which provides that the Service will not raise issues concerning the tax effects resulting from possible prohibited transactions arising from certain cash, property or services offered by financial institutions to individuals for whom the financial institution maintains certain IRAs and Keogh Plans. See Announcement 90–1, 1990–2 I.R.B. 31, (January 1, 1990).

[4] In this regard, the Department has consulted with the Service regarding the application of Announcement 90–1. The Service has indicated that the Announcement will continue to be in effect during this 120 day period.

[5] See 56 FR 8367.

General Information

The attention of interested persons is directed to the following:

(1) In accordance with section 4975(c)(2) of the Code, and based upon the entire record, the Department finds that the exemption is administratively feasible, in the interests of the IRAs and Keogh Plans and of their participants and beneficiaries and protective of the rights of participants and beneficiaries of such plans.

(2) The exemption is supplemental to, and not in derogation of the Code, including statutory or administrative exemptions and transitional rules. Furthermore, the fact that a transaction is subject to an administrative or statutory exemption is not dispositive of whether the transaction is in fact a prohibited transaction.

(3) The exemption is applicable to a transaction only if the conditions specified in the exemption are met.

Exemption

Accordingly, the following exemption is granted under the authority of section 4975(c)(2) of the Code and in accordance with the procedures set forth in ERISA Procedure 75–1 (40 FR 18471, April 28, 1975).

Section I: Covered Transaction

Effective May 11, 1993, the sanctions resulting from the application of section 4975 of the Code, including the loss of exemption of an individual retirement account (IRA) pursuant to section 408(e)(2)(A) of the Code, by reason of section 4975(c)(1) (D), (E) and (F) of the Code, shall not apply to the receipt of services at reduced or no cost by an individual for whose benefit an IRA or, if self-employed, a Keogh Plan, is established or maintained, or by members of his or her family, from a bank pursuant to an arrangement in which the deposit balance in the IRA or Keogh Plan is taken into account for purposes of determining eligibility to receive such services, provided that each condition of section II of this exemption is satisfied.

Section II: Conditions

(a) The IRA or Keogh Plan, the deposit balance of which is taken into account for purposes of determining eligibility to receive services at reduced or no cost, is established and maintained for the exclusive benefit of the participant covered under the IRA or Keogh Plan, his or her spouse or their beneficiaries.

(b) The services must be of the type that the bank itself could offer consistent with applicable federal and state banking law.

(c) The services are provided by the bank (or an affiliate of the bank) in the ordinary course of the bank's business to customers who qualify for reduced or no cost banking services but do not maintain IRAs or Keogh Plans with the bank.

(d) For the purpose of determining eligibility to receive services at reduced or no cost, the deposit balance required by the bank for the IRA or Keogh Plan is equal to the lowest balance required for any other type of account which the bank includes to determine eligibility to receive reduced or no cost services.

(e) The rate of return on the IRA or Keogh Plan investment is no less favorable than the rate of return on an identical investment that could have been made at the same time at the same branch of the bank by a customer of the bank who is not eligible for (or who does not receive) reduced or no cost services.

Section III: Definitions

The following definitions apply to this exemption:

(a) The term bank means a bank described in section 408(n) of the Code.

(b) The term IRA means an individual retirement account described in Code section 408(a). For purposes of this exemption, the term IRA shall not include an IRA which is an employee benefit plan covered by title I of ERISA.

(c) The term Keogh Plan means a pension, profit sharing, or stock bonus plan qualified under Code section 401(a) and exempt from taxation under Code section 501(a) under which some or all of the participants are employees described in section 401(c) of the Code. For purposes of this exemption, the term Keogh Plan shall not include a Keogh Plan which is an employee benefit plan covered by title I of ERISA.

(d) The term deposit balance means deposits as that term is defined under 29 CFR 2550.408b–4(c)(3).

(e) An affiliate of a bank includes any person directly or indirectly controlling, controlled by, or under common control with the bank. The term control means the power to exercise a controlling influence over the management or policies of a person other than an individual.

(f) The term members of his or her family refers to beneficiaries of the individual for whose benefit the IRA or Keogh Plan is established or maintained, who would be members of the family as that term is defined in Code section 4975(e)(6), or a brother, a sister, or spouse of a brother or a sister.

(g) The term service includes incidental products of a *de minimis* value provided by third persons, pursuant to an arrangement with the bank, which are directly related to the provision of banking services covered by the exemption.

Signed at Washington, DC, this 5th day of January 1993.

Alan D. Lebowitz,

Deputy Assistant Secretary of Program Operations, Pension and Welfare Benefits Administration, U.S. Department of Labor.

[FR Doc. 93–539 Filed 1–8–93; 8:45 am]

BILLING CODE 4510–29–M

[Application Number D–9124]

Proposed Amendment to Prohibited Transaction Exemption 93–2 (PTE 93–2) for the Receipt of Certain Services by Individuals for Whose Benefit Individual Retirement Accounts or Retirement Plans for Self-Employed Individuals Have Been Established or Maintained

AGENCY: Pension and Welfare Benefits Administration, U.S. Department of Labor.

ACTION: Notice of Proposed Amendment to PTE 93–2.

SUMMARY: This document contains a notice of pendency before the Department of Labor of a proposed amendment to PTE 93–2. PTE 93–2 is a class exemption that permits the receipt of services at reduced or no cost by an individual for whose benefit an individual retirement account (IRA) or, if self-employed, a Keough Plan, is established or maintained, or by members of his or her family, from a bank, provided the conditions of the exemption are met. The proposed amendment, if adopted, would affect individuals with a beneficial interest in the IRAs who receive such services as well as the banks that provide such services.

DATES: If adopted, the proposed amendment would be effective as of May 11, 1993, the effective date of PTE 93–2. Written comments and requests for a public hearing should be received by the Department on or before February 25, 1993.

ADDRESSES: All written comments and requests for a public hearing (preferably three copies) should be addressed to the U.S. Department of Labor, Office of Exemption Determinations, Pension and Welfare Benefits Administration, room N–5649, 200 Constitution Avenue, NW., Washington, DC 20210, (ATTN: D–9124).

FOR FURTHER INFORMATION CONTACT: Ms. Allison K. Padams, Office of Exemption Determinations, Pension and Welfare Benefits Administration, U.S.

Department of Labor, (202) 523–8971 (this is not a toll-free number); or Ms. Susan E. Rees, Plan Benefits Security Division, Office of the Solicitor, U.S. Department of Labor, (202) 523–9141 (this is not a toll-free number).

SUPPLEMENTARY INFORMATION: Notice is hereby given of the pendency before the Department of a proposed amendment to PTE 93–2. The amendment would provide relief from the restrictions of sections 406(a)(1)(D) and 406 (b) of the Employee Retirement Income Security Act of 1974 the (ERISA) and the sanctions resulting from the application of sections 4975(a) and (b), 4975(c)(3) and 408(e)(2) of the Internal Revenue Code of 1986 (the Code) by reason of section 4975(c)(1) (D), (E) and (F) of the Code.

By notice appearing elsewhere in this issue of the **Federal Register**, the Department has granted PTE 93–2 to permit the receipt of services at reduced or no cost by an individual for whose benefit an IRA or Keough Plan is established or maintained, or by members of his or her family, from a bank pursuant to an arrangement in which the deposit balance in the IRA or Keough Plan is taken into account for purposes of determining eligibility to receive such services, provided that the conditions of the exemption are met.[1] PTE 93–2 provides an exemption from the sanctions resulting from the application of sections 4975(a) and (b), 4975(c)(3) and 408(e)(2) of the Code by reason of section 4975(c)(1) (D), (E) and (F) of the Code.[2]

In response to the proposed exemption for the receipt of relationship banking services,[3] a number of commenters (the Commenters) urged the Department to expand the exemption to provide relief for transactions involving individuals for whose benefit a simplified employee plan (SEP), as defined under section 408(k) of the Code, is established or maintained. Since the Department did not previously propose relief from sections 406(a)(1)(D) and 406(b), it would not be appropriate to grant such relief as part of the final exemption because the proposed exemption did not offer interested persons an opportunity to present their views with respect to the Department's contemplated action. Because the Department was desirous of not delaying the grant of relief from section 4975(c)(1)(D), (E), and (F) of the Code for transactions involving IRAs and Keogh Plans not covered by title I of ERISA, the Department decided to adopt PTE 93–2, and to propose an amendment which would extend the relief provided pursuant to PTE 93–2 to individuals for whose benefit SEPs have been established or maintained. The Department is proposing this relief on its own motion, pursuant to section 408(a) of ERISA and section 4975(c)(2) of the Code and in accordance with the procedures set forth in 29 CFR part 2570, subpart B (55 FR 32836, August 10, 1990).

According to the Commenters, SEP arrangements are, for all practical purposes, no different than other IRAs covered by PTE 93–2, and the banking industry makes no distinction between a SEP-IRA and any other IRA. In this regard, the Commenters indicated that a SEP is an IRA which is funded by employer contributions. Once an employer makes the required contributions to a participant's SEP, the employer's role with respect to the SEP is limited. A participant owns and controls his SEP like any other IRA. Thus, participants generally are free to transfer the employer contributions to other IRAs or withdraw them at any time.

Based on the arguments presented by the Commenters and the additional protections already embodied in PTE 93–2, it appears to the Department that the safeguards of PTE 93–2 would not be diminished by the proposed amendment. However, the Department is of the view that the exemption should not be available to SEP arrangements which restrict the participant's ability to transfer assets from the SEP to an IRA maintained at a financial institution of the participant's choice. Therefore, the Department has decided to propose relief for SEPs that provide participants with the unrestricted authority to transfer the assets to IRAs sponsored by different financial institutions. In this regard, the Department requests that interested persons, in addition to other comments, describe how a relationship banking program would operate with respect to SEPs, and whether additional safeguards are necessary in order to protect the interests of the participants and beneficiaries of SEPs.

The Department notes that the exemption will not be available for the receipt of services by third persons other than those described in the exemption. Thus, for example, no relief would be available under the exemption for the receipt of services by the employer establishing or maintaining the SEP on behalf of its employees.

Notice to Interested Persons

Because many participants in SEPs and financial institutions sponsoring SEPs could conceivably be considered interested persons, the only practical form of notice is publication in the **Federal Register**.

General Information

The attention of interested persons is directed to the following:

(1) Before an exemption may be granted under section 408(a) of ERISA and section 4975(c)(2) of the Code, the Department must find that the exemption is administratively feasible, in the interests of the IRAs and their participants and beneficiaries and protective of the rights of participants and beneficiaries of such plans.

(2) The proposed amendment, if granted, will be supplemental to, and not in derogation of, any other provisions of ERISA and the Code, including statutory or administrative exemptions and transitional rules. Furthermore, the fact that a transaction is subject to an administrative or statutory exemption is not dispositive of whether the transaction is in fact a prohibited transaction.

(3) If granted, the proposed amendment will be applicable to a transaction only if the conditions specified in the class exemption are met.

Written Comments and Hearing Request

All interested persons are invited to submit written comments or requests for a public hearing on the proposed exemption to the address and within the time period set forth above. All comments will be made a part of the record. Comments and requests for a hearing should state the reasons for the writer's interest in the proposed exemption. Comments received will be available for public inspection with the

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[1] PTE 93–2 applies only to IRAs described in section 408(a) of the Code which are not "employee benefit plans" covered by title I of ERISA.

29 CFR 2510.3–2(d) explains that IRAs described in section 408(a) of the Code will not be considered pension plans subject to title I of ERISA, provided that: (1) No contributions to the plan are made by the employer of employee association; (2) participation is completely voluntary for employees or members; (3) the sole involvement of the employer or employee organization is without endorsement to permit the sponsor to publicize the program, to collect contributions on behalf of the sponsor through payroll deductions or dues checkoffs and to remit them to the sponsor; and (4) the employer or employee organization receives no consideration in the form of cash or otherwise other than reasonable compensation for services actually rendered in connection with payroll deductions or dues checkoffs.

[2] Section 102 of Reorganization Plan No. 4 of 1978 (43 FR 47713, October 17, 1978) generally transferred the authority of the Secretary of the Treasury to issue administrative exemptions under section 4975(c)(2) of the Code to the Secretary of Labor.

[3] See Proposed Class Exemption for the Receipt of Certain Services by Individuals Establishing or Maintaining Individual Retirement Accounts or Retirement Plans for Self-Employed Individuals (56 FR 8365, February 28, 1991).

referenced application at the above address.

Proposed Amendment

Under section 408(a) of ERISA and section 4975(c)(2) of the Code and in accordance with the procedures set forth in 29 CFR Part 250, Subpart B (55 FR 32836, August 10, 1990), the Department proposes to amend PTE 93–2 as set forth below:

(1) Section I is amended to read: "Effective May 11, 1993, the restrictions of sections 406(a)(1)(D) and 406(b) of ERISA and the sanctions resulting from the application of section 4975 of the Code, including the loss of exemption of an IRA pursuant to section 408(e)(2)(A) of the Code, by reason of section 4975(c)(1) (D), (E) and (F) of the Code, shall not apply to the receipt of services at reduced or no cost by an individual for whose benefit an IRA or Keogh Plan is established or maintained, or by members of his or her family, from a bank, pursuant to an arrangement in which the deposit balance in the IRA or Keogh Plan is taken into account for purposes of determining eligibility to receive such services, provided that each condition of section II of this exemption is satisfied."

(2) Section III(b) is amended to read: The term IRA means an individual retirement account described in Code section 408(a). For purposes of this exemption, the term IRA shall not include an IRA which is an employee benefit plan covered by title I or ERISA, except for a Simplified Employee Pension (SEP) described in section 408(k) of the Code which provides participants with the unrestricted authority to transfer their SEP balances to IRAs sponsored by different financial institutions.

Signed at Washington, DC, this 5th day of January, 1993.

Alan D. Lebowitz,

Deputy Assistant Secretary for Program Operations, Pension and Welfare Benefits Administration, U.S. Department of Labor.

[FR Doc. 93–540 Filed 1–8–93; 8:45 am]

BILLING CODE 4510-29-M

[Prohibited Transaction Exemption 93–1; Application Number D–4064]

Class Exemption for Certain Transactions by Individuals for Whose Benefit Individual Retirement Accounts or Retirement Plans for Self-Employed Individuals Have Been Established or Maintained

AGENCY: Pension and Welfare Benefits Administration, U.S. Department of Labor.

ACTION: Grant of class exemption.

SUMMARY: This document contains a final exemption from certain prohibited transaction restrictions of the Internal Revenue Code of 1986 (the Code). The class exemption permits the receipt of certain cash, premiums or other consideration paid to an individual in connection with a transaction involving an individual retirement account (IRA) or a retirement plan for a self-employed individual (Keogh Plan), provided that the conditions of the exemption are met. The exemption affects individuals with a beneficial interest in the IRAs or Keogh Plans who receive such premiums or gifts, as well as the financial institutions which provide the payments.

EFFECTIVE DATE: January 1, 1975.

FOR FURTHER INFORMATION CONTACT: Allison K. Padams, Office of Exemption Determinations, Pension and Welfare Benefits Administration, U.S. Department of Labor, (202) 523–8971 (this is not a toll-free number; or Susan E. Rees, Plan Benefits Security Division, Office of the Solicitor, U.S. Department of Labor, (202) 523–9141 (this is not a toll-free number).

SUPPLEMENTARY INFORMATION: On February 1, 1983, the Department of Labor (the Department) and the Internal Revenue Service (the Service) published a notice of proposed class exemption (48 FR 4592) from the sanctions resulting from the application of sections 4975 (a) and (b), 4975(c)(3) and 408(e)(2) of the Code by reason of section 4975(c)(1) of the Code.[1] The transactions involve the payment of cash, premiums and other consideration to individuals in connection with establishment of, or contribution to an IRA or Keogh Plan by organizations authorized to sponsor IRAs or Keogh Plans. Because of the apparent prevalence of this type of transaction, the Department and the Service proposed the class exemption on their own motion pursuant to section 4975(c)(2) of the Code, and in accordance with the procedures set forth in Rev. Proc. 75–26 (1975–1 C.B. 722) and ERISA Procedure 75–1 (40 FR 18471, April 28, 1975).

The notice of pendency invited interested persons to submit written comments or request that a public hearing be held on the proposed exemption. Over twenty public comments and requests for a public hearing with regard to the proposed class exemption were received pursuant to section 4975(c)(2) of the Code and in accordance with the procedures set forth in Rev. Proc. 75–26 and in ERISA Procedure 75–1. Notice of a public hearing was published on July 1, 1983 (48 FR 30510), and the public hearing was held on August 17, 1983. To date, the Department has not granted relief for the transactions described in the proposed exemption.

Recently, it came to the attention of the Department that many financial institutions may no longer offer premiums as incentives for their customers to establish IRAs or Keogh Plans with their particular institutions. Rather, it appeared that financial institutions were offering banking services at reduced or no cost as an inducement to customers to begin or expand banking relationships. Consequently, the Department published a notice in the **Federal Register** (56 FR 8368, February 28, 1990) in which it requested comments from interested persons regarding the disposition of the proposed class exemption (the Notice to Solicit Comments).[2]

The Notice to Solicit Comments gave interested persons an opportunity to submit written comments to be considered by the Department in deciding whether or not to provide exemptive relief for the receipt of cash, premiums, or other consideration by an individual in connection with the establishment of, or contribution to, an IRA or Keogh Plan. Specifically, the Department requested that interested persons provide current information on the extent of the need for exemptive relief for transactions of this type and the standards and safeguards upon which exemptive relief should be conditioned. Ten comments were received pursuant to the Notice to Solicit Comments.

Upon consideration of the entire record in this matter, including all the comments received and testimony offered at the public hearing, the Department has determined to grant the proposed class exemption subject to certain modifications.

Description of the Proposal

The 1983 Proposal provided retroactive and prospective relief from the sanctions resulting from the

[1] Section 102 of Reorganization Plan No. 4 of 1978 (43 FR 47713, October 17, 1978) generally transferred the authority of the Secretary of the Treasury to issue administrative exemptions under section 4975(c)(2) of the Code of the Secretary of Labor.

[2] By notice appearing elsewhere in this issue of the **Federal Register**, the Department has granted a conditional class exemption which permits the receipt of certain services at reduced or no cost by an individual, for whose benefit an IRA or Keogh Plan is established or maintained, from a bank.

application of 4975 of the Code, including the loss of exemption of an IRA pursuant to section 408(e)(2)(A) of the Code, by reason of section 4975(c)(1) of the Code, for the payment of cash, property or other consideration by an organization authorized to sponsor IRAs or Keogh Plans, to an individual establishing or contributing to an IRA or Keogh Plan or to members of his or her family as defined by section 4975(e)(6) of the Code.

The proposal contained specific conditions designed to insure that the transactions did not conflict with the basic purpose of such plans which is to provide retirement savings for participants and their beneficiaries. Thus, the IRA or Keogh Plan must be established solely to benefit the person receiving the cash, property or other consideration, his or her spouse, and their beneficiaries. The fair market value of the property or other consideration which may be measured by its cost to the financial institution, or the cash received, must not exceed $10 for a deposit of less than $5,000 and $20 for a deposit of $5,000 or more. The conditions of the proposed exemption did not specifically limit the form the premium or other consideration may take.

The Department also noted in the preamble to the proposal that the exemption would not be available for transactions involving IRAs or Keogh Plans which are subject to title I of ERISA.[3] Nor would the exemption be available to exempt the receipt of cash, property or other consideration by third persons other than those described in the exemption.

[3] 29 CFR 2510.3–2(d) explains that IRAs described in section 408(a) of the Code will not be considered pension plans subject to title I of ERISA, provided that: (1) No contributions to the plan are made by the employer or employee-association; (2) participation is completely voluntary for employees or members; (3) the sole involvement of the employer or employee organization is without endorsement to permit the sponsor to publicize the program, to collect contributions on behalf of the sponsor through payroll deductions or dues checkoffs and to remit them to the sponsor; and (4) the employer or employee organization receives no consideration in the form of cash or otherwise other than reasonable compensation for services actually rendered in connection with payroll deductions or dues checkoffs.

29 CFR 2510.3–3(b) explains that for purposes of title I of ERISA, "employee benefit plan" shall not include a Keogh Plan under which no employees are covered under the plan. In this regard, 29 CFR 2510.3–3(c) states that for purposes of the above referenced section: (1) An individual and his or her spouse shall not be deemed to be employees with respect to a trade or business, whether incorporated or unincorporated, which is wholly owned by the individual and his or her spouse; and (2) a partner in a partnership and his or her spouse shall not be deemed to be employees with respect to the partnership.

The Department proposed the class exemption based upon its understanding that it was common practice for financial institutions to offer premiums in connection with the establishment of, or the additional contribution to, an IRA or Keogh Plan. The Department also recognized that the apparent prevalence of this type of transaction could result in adverse consequences to a large number of individuals establishing IRAs and Keogh Plans.

Discussion of the Comments

I. Major Issues Raised in Response to the 1983 Notice of Proposed Exemption and Public Hearing

Several commenters suggested that no exemption was necessary because the transactions described in the proposed exemption are not prohibited transactions under section 4975(c)(1) of the Code. In this regard, section 4975(c)(1) of the Code prohibits, in relevant part, the transfer to, or use by or for the benefit of, a disqualified person of the income or assets of a plan (4975(c)(1)(D)); an act by a disqualified person who is a fiduciary whereby he deals with the income or assets of a plan in his own interest or for his own account (4975(c)(1)(E)); and the receipt of any consideration for his own personal account by any disqualified person who is a fiduciary from any party dealing with the plan in connection with a transaction involving the income or assets of plan (4975(c)(1)(F)). The Department disagrees with these comments. The term "disqualified person", as defined in Code section 4975(e)(2), includes a fiduciary and a person providing services to the plan. Persons who exercise discretionary authority or control over the assets of a plan, including IRAs and Keogh Plans, are fiduciaries subject to the restrictions imposed by section 4975(c)(1) of the Code.[4] Thus the receipt of cash, premiums or other consideration by such individuals in connection with the investment of his or her IRA or Keogh Plan assets is a transaction prohibited under section 4975(c)(1) of the Code.[5] In the absence of an exemption, the individual who receives such cash, premiums or other consideration and the plan involved may be subject to the sanctions applied under section 408(e)(2) and 4975(c)(1) of the Code. To clarify the Department's position, the final exemption now specifies the subsections of section 4975(c)(1) from which relief is provided.

A number of commenters expressed concern that the exemption would discourage financial institutions from providing IRA and Keogh Plan participants with customary financial services, such as free checking accounts and free check-cashing privileges which have traditionally been based on account balances maintained by a customer at the financial institution. It was represented that these services, unlike such premiums as toasters and radios, cannot readily be valued because their cost varies greatly among institutions and recipients. In this regard, the Department notes that a separate exemption for the receipt of certain services buy individuals covered under individual retirement accounts or retirement plans for self-employed individuals is published in today's **Federal Register**. Consequently, the Department has determined not to revise the subject exemption in this regard.

Several commenters recommended that institutions be permitted to pay premiums with respect to an IRA or Keogh Plan on an annual or more frequent basis without regard to whether additional contributions have been made. The Department is not persuaded by the commenters that such an expansion would be appropriate. Another commenter urged the Department to permit the payment of premiums with respect to each contribution made to an IRA or Keogh Plan. The commenters suggested that failure to allow such payments may result in IRA and Keogh Plan assets being transferred to another financial institution solely to obtain additional premiums. The Department generally believes that most plan participants are more concerned with their future retirement income and the terms and conditions of the various investment options offered at particular financial institutions than with the *de minimis* premiums permitted by this exemption. Nevertheless, the Department recognizes that some IRA and Keogh funds may be transferred from institution to institution in order to receive a premium. Accordingly, the Department has determined to modify the final exemption to permit the payment of cash, premiums or other consideration in connection with the making of additional contributions to an established IRA or Keogh Plan, including the transfer of assets from another plan.

A number of commenters urged the Department to delete or modify the $10 and $20 limits under the proposed

[4] See section 4975(e)(3) of the Code.

[5] See Advisory Opinion 89–12A (July 14, 1989)

exemption. Several commenters suggested that the exemption permit market forces to establish the dollar limitations. Another commenter suggested a "rule of reasonableness" or a maximum limit set as a percentage of the total IRA (or Keogh Plan) investment. The Department believes that deleting or increasing the dollar limits, or substituting a maximum limit set as a percentage of total plan investment, could have an adverse impact on IRAs and Keogh Plans by creating an incentive for individuals to make IRA or Keogh Plan investments at a particular financial institution for reasons unrelated to the purposes for which such plans are established, i.e. to provide retirement income. Regarding the other suggested modifications to the dollar limits, the Department does not believe it would be appropriate to revise these limits in this regard since adoption of these suggestions would necessitate a subjective determination of the appropriate limit.

A number of commenters suggested that the relief provided by the class exemption should be given retroactive application without any dollar limitation on the amount of the premiums and that the dollar limitations should only apply prospectively. The Department is not persuaded by the commenters' arguments regarding additional retroactive relief. In this regard, the Department notes that financial institutions were aware of the dollar limitations found in the Notice of Proposed Exemption,[6] and had the opportunity to alter their banking programs accordingly. Additionally, the Department wishes to note that on January 8, 1990, the Service issued an IRA nonenforcement policy (the IRA Nonenforcement Policy),[7] which provides that the Service will not raise issues concerning the tax effects resulting from possible prohibited transactions arising from certain cash, property or services offered by financial institutions described in section 408(n) of the Code to individuals for whom the financial institution maintains certain IRAs and Keogh Plans. The IRA Nonenforcement Policy applies to the cash, property or other consideration described in the 1983 Proposal.

Several commenters urged the Department to clarify that the exemption provides relief for the provision by a credit union of life insurance coverage to members who maintain or establish IRAs and Keogh Plans at such credit union.[8] According to the commenters, it is a long established and customary practice for a credit union to provide life insurance, in an amount equal to the balance of the savings of its members, including IRA and Keogh Plan accounts. Each credit union determines the maximum level of insurance coverage that it will furnish its members. One commenter stated that 99% of all credit unions currently limit life insurance coverage to $5,000 per member. The insurance is provided by credit unions through the purchase of group term life insurance policies with coverages in an amount equal to each member's total account balance up to the maximum amount established by the particular credit union.

According to the commenters, in calculating the dollar amount of insurance coverage, a credit union generally considers the relevant accounts maintained by an individual in the order in which they are established. Since the value of the insurance attributable to the IRA or Keogh Plan balance may differ from member to member depending upon the number of other accounts maintained by the member, the maximum level of coverage selected by the credit union, and the order in which each account is opened, the commenter argued that it would be difficult for the financial institutions to comply with the dollar limitations with regard to these insurance programs. Additionally, because the nature of life insurance contemplates that coverage be maintained from year to year, it would raise administrative problems for the financial institutions, and prove disadvantageous to members, if additional contributions were required in order to maintain insurance coverage from year to year. On the basis of these comments, the Department has determined that it would be appropriate to modify the final exemption to permit the provision of group term life insurance by a financial institution.

Accordingly, we have revised the exemption to provide additional relief for the provision of life insurance subject to a requirement limiting the amount of coverage that may be provided. Thus, under the final exemption, where a financial institution takes into account an IRA or Keogh Plan balance in determining eligibility for life insurance, the amount of insurance that is attributable on a dollar for dollar basis to the IRA or Keogh Plan deposit balance may not exceed $5,000.

II. Major Issues Raised in Response to the 1991 Notice to Solicit Comments

Nine commenters urged the Department to finalize the proposed exemption. These commenters indicated that financial institutions may still offer premiums to attract customers. One commenter requested that the Department withdraw the proposed exemption.

Several of these commenters requested that the Department increase the dollar limitations on the value of the cash, premiums or other consideration to account for inflation. The Department is not persuaded by the comments submitted in favor for this modification. The Department continues to believe that the value of the cash, premiums or other consideration allowed under the exemption must be *de minimis* to assure that such transactions do not conflict with the basic purpose of IRAs and Keogh Plans which is to provide retirement savings for participants and their beneficiaries.

III. Miscellaneous

For purposes of clarification, the Department has defined the terms "IRA" and "Keogh Plan" under the final exemption. In addition, the definition of "members of his or her family" has been modified to make it consistent with the definition contained in the class exemption for the receipt of certain services at reduced or no cost by an individual for whose benefit an IRA or a Keogh is established and maintained from a bank which is published in this issue of the **Federal Register**.

General Information

The attention of interested persons is directed to the following:

(1) The fact that a transaction is the subject of an exemption under section 4975(c)(2) of the Code does not relieve a fiduciary or other disqualified person from certain other provisions of the Code. These provisions include any prohibited transaction provisions in section 4975(c)(1) to which the exemption does not expressly apply; nor does the exemption affect the requirement of section 408(a) of the Code that an IRA must operate for the exclusive benefit of the individual for whose benefit the IRA is maintained and his or her beneficiaries, or the requirement of section 401(a) of the Code that a plan must operate for the exclusive benefit of the employees of

[6] See 48 FR 4592, at 4593.

[7] Announcement 90–1, 1990–2 I.R.B. 31 (January 8, 1990).

[8] The Credit Union National Association Inc., (CUNA) was among the commenters who raised this issue. Additionally, CUNA provided comments on the proposed exemption for the receipt of certain services by individuals establishing or maintaining Individual Retirement Accounts or Retirement Plans for Self-Employed Individuals (56 FR 8365, February 28, 1991), and filed an individual exemption request to permit credit unions to provide members with such life insurance coverage.

the employer maintaining the plan and their beneficiaries.

(2) This exemption is supplemental to, and not in derogation of, any other provisions of the Code, including statutory or administrative exemptions and transitional rules. Furthermore, the fact that a transaction is subject to an administrative or statutory exemption is not dispositive of whether the transaction is in fact a prohibited transaction.

(3) The class exemption is applicable to a particular transaction only if the transaction satisfies the conditions specified in the class exemption.

(4) In accordance with section 4975(c)(2) of the Code and the procedures set forth in ERISA Procedure 75–1 (40 FR 18471, April 28, 1975), and based upon the entire record, the Department has made the following determinations:

(i) The exemption is administratively feasible;

(ii) It is in the interest of the individuals for whose benefit the IRA and Keogh Plans are maintained; and

(iii) It is protective of the rights of those individuals and their beneficiaries.

Exemption

Accordingly, the following exemption is granted under the authority of section 4975(c)(2) of the Code, and in accordance with the procedures set forth in ERISA Procedure 75–1.

I. Effective January 1, 1975, the sanctions resulting from the application of section 4975 of the Code, including the loss of exemption of an IRA pursuant to section 408(e)(2)(A) of the Code, by reason of section 4975(c)(1)(D), (E) and (F) of the Code, shall not apply to the payment of cash, property, or other consideration by an organization authorized to sponsor IRAs or Keogh Plans, to an individual for whose benefit an IRA or Keogh Plan is established or maintained, or to members of his or her family provided that:

(a) The IRA or Keogh Plan in connection with which cash, property or other consideration is given, is established solely to benefit the participant, his or her spouse and their beneficiaries;

(b) The cash, property or other consideration is given only in connection with the establishment of the IRA or Keogh Plan or the making of an additional contribution, including the transfer of assets from another plan, to an existing IRA or Keogh Plan.

(c) During any taxable year, the total of the fair market value of the property or other consideration to the sponsor of the IRA or Keogh Plan, and the cash received is not more than:

(1) $10 for deposits to the IRA or Keogh Plan of less than $5,000; and

(2) $20 for deposits to the IRA or Keogh Plan of $5,000 or more.

(d) In any case where the consideration provided by a financial institution to an individual for whose benefit an IRA or Keogh Plan is established or maintained, is group term life insurance, the limitations set forth in conditions (b) and (c) shall not apply to the provision of such insurance if, during any taxable year, no more than $5,000 of the face value of the insurance is attributable on a dollar for dollar basis to the assets of the IRA or Keogh Plan.

II. Definitions

(a) The term "taxable year" means the taxable year of the individual. In determining the taxable year for payments in connection with transfers of assets from previously established plans, the calendar year in which the transfer is received by the organization is deemed to be the taxable year of the individual.

(b) The "fair market value of the cash, property or other consideration" given may be measured by the cost to the financial institution.

(c) The term "members of his or her family" refers to beneficiaries of the individual for whose benefit the IRA or Keogh Plan is established or maintained, who would be members of the family as that term is defined in Code section 4975(e)(6), or a brother, a sister, or spouse of a brother or a sister.

(d) The term "IRA" means an individual retirement account described in Code section 408(a). For purposes of this exemption, the term IRA shall not include an IRA which is an employee benefit plan covered by title I of ERISA.

(e) The term "Keogh Plan" means a pension, profit sharing or stock bonus plan qualified under Code section 401(a) and exemption from taxation under Code section 501(a) under which some or all of the participants are employees described in section 401(c) of the Code. For purposes of this exemption the term Keogh Plan shall not include a Keogh Plan which is an employee benefit plan covered by title I or ERISA.

Signed at Washington, DC, this 5th day of January 1993.

Alan D. Lebowitz,

Deputy Assistant Secretary for Program Operations, Pension and Welfare Benefits Administration, U.S. Department of Labor.

[FR Doc. 93–541 Filed 1–8–93; 8:45 am]

BILLING CODE 4510–29–M

NATIONAL ADVISORY COUNCIL ON THE PUBLIC SERVICE

NACPS to Hold Public Hearing, Friday, February 5, 1993

SUMMARY: The National Advisory Council on the Public Service will hold a public hearing on the Federal government as an employer. The hearing is scheduled for Friday, February 5, 1993, in the hearing room of the Nuclear Regulatory Commission, 11555 Rockville Pike, Rockville, Maryland from 9:30 a.m. to 12 noon.

Invited witnesses will give testimony to the Council on such issues as recruiting and retention, model human resources programs, career development programs, women in the Federal workforce and family-friendly policies.

The hearing will be open to the public. Time will be allotted to those persons wishing to make comment to the Council concerning the Federal Employment. Any person or organization wishing to reserve time to make public comment during the hearing should pre-register by calling the Council at 202–724–0796 before February 1. Those persons who do not pre-register to make comments cannot be guaranteed an opportunity to do so. The Council also welcomes written comments on Federal workforce issues, which should be sent to the Council office at 420 National Press Building, 529 14th Street, NW., Washington, DC 20045.

For more information and for media coverage, contact Rhea Farberman at 202–724–0796.

Issued January 6, 1993.

Jean M. Curtis,

Executive Director, National Advisory Council on the Public Service.

[FR Doc. 93–462 Filed 1–8–93; 8:45 am]

BILLING CODE 75-25-01

NATIONAL COMMISSION ON AMERICAN INDIAN, ALASKA NATIVE, AND NATIVE HAWAIIAN HOUSING

Meeting

AGENCY: The National Commission on American Indian, Alaska Native, and Native Hawaiian Housing.

ACTION: Meeting notice.

SUMMARY: In accordance with the Federal Advisory Committee Act, Public Law 92–463, as amended, the National Commission on American Indian, Alaska Native, and Native Hawaiian Housing announces the forthcoming meeting of the Commission.

DATES: January 26, 1993, 9 a.m. to 5 p.m.

ADDRESSES: Holiday Inn Downtown, The Governor's House, 17th & Rhode Island, NW., Washington, DC., (202) 296–2100.

FOR FURTHER INFORMATION CONTACT: Lois V. Toliver, Administrative Officer, (202) 275–0045.

SUPPLEMENTARY INFORMATION:

Type of Meeting: Open.

Agenda: Call to Order, Roll Call, Chairman's Message, Update of Commission Activities, Committee Reports, Commission Strategy Session.

Lois V. Toliver,

Administrative Officer.

[FR Doc. 93–444 Filed 1–8–93; 8:45 am]

BILLING CODE 6820–07–M

NATIONAL COMMISSION ON MANUFACTURED HOUSING

Meeting

AGENCY: National Commission on Manufactured Housing.

ACTION: Notice of meeting.

SUMMARY: In accordance with the Federal Advisory Committee Act, Public Law 101–625, as amended, the National Commission on Manufactured Housing announces a forthcoming meeting of the Commission.

DATES: January 7, 1993, 9 a.m–5 p.m.; January 8, 1993, 9 a.m.–5 p.m.

ADDRESSES: Hyatt Regency, 400 New Jersey Avenue, Washington, DC 20001, Bryce Room.

FOR FURTHER INFORMATION CONTACT: Carmelita R. Pratt, Administrative Officer, The National Commission on Manufactured Housing, (GSA) 7th & D Street, SW., #7109, Washington. DC 20407 (202) 708–5702.

TYPE OF MEETING: Open.

Due to scheduling difficulties, this notice could not be published 15 days prior to this meeting as required by Federal Advisory Committee Act.

Carelita R. Pratt,

Administrative Officer.

[FR Doc. 93–455 Filed 1–8–93; 8:45 am]

BILLING CODE 6820–EA–M

NUCLEAR REGULATORY COMMISSION

Abnormal Occurrences for Third Quarter CY 1992; Dissemination of Information

Section 208 of the Energy Reorganization Act of 1974, as amended, requires the NRC to disseminate information on abnormal occurrences (i.e., unscheduled incidents or events that the Commission determines are significant from the standpoint of public health and safety). During the third quarter of CY 1992, the following incidents at NRC licensees were determined to be abnormal occurrences (AOs) and are described below, together with the remedial actions taken. The events are also being included in NUREG–0090, Vol. 15, No. 3 ("Report to Congress on Abnormal Occurrences: July—September 1992"). This report will be available at the NRC's Public Document Room, 2120 L Street NW. (Lower Level), Washington, DC 20555 about three weeks after the publication date of this **Federal Register** Notice.

Other NRC Licensees

(Industrial Radiographers, Medical Institutions, Industrial Users, etc.)

92–9 Medical Therapy Misadministration at Cooper Hospital/University Medical Center in Camden, New Jersey

One of the AO reporting guidelines notes that a therapeutic misadministration affecting two or more patients at the same facility can be considered an abnormal occurrence.

Date and Place—November 11, 1991 to January 7, 1992; Cooper Hospital/University Medical Center; Camden, New Jersey.

Nature and Probable Consequences—On January 27, 1992, the NRC Region I office was notified by telephone that five therapeutic misadministrations involving Iridium-192 (Ir-192) wire occurred at Cooper Hospital/University Medical Center at Camden, New Jersey from November 11, 1991 to January 7, 1992. The licensee had discovered the error on January 24, 1992, after the review of patient charts in preparation for the Quality Management Program submittal. The error caused a 12.2 percent underdosing of the patients.

Four patients received external beam therapy (Linear Accelerator) in addition to the radiation received from the Ir-192 implants. Patient A was to receive 1043 rads from an Ir-192 intracavitary bronchial implant for the treatment of lung cancer and received 916 rads on November 11, 1991. Patient A later received 5576 rads from external beam therapy. Patient B was to receive 1266 rads to the head and neck from an Ir-192 interstitial implant for the treatment of cancer and received 1112 rads on November 12, 1992. Patient B later received 4600 rads from external beam therapy. Patient C was to receive 2150 rads from an Ir-192 interstitial implant for the treatment of breast cancer and received 1888 rads on December 2, 1991. Patient C later received 5940 rads from external beam therapy. Patient D was to receive 2000 rads to the tongue for the treatment of cancer from an Ir-192 interstitial implant and received 1756 rads on January 7, 1992. Patient D later received 5940 rads from external beam therapy. The licensee has determined that the above patient's treatment were not compromised by the small decrease in the total dose received when the external beam therapy treatment is factored into the assessment.

One patient did not receive external beam therapy. On November 21, 1991, Patient E was prescribed to receive 4628 rads to the pelvis for the treatment of cancer from an Ir-192 interstitial implant and received 4063 rads. Patient E's attending physician had originally calculated a desired dose between 4000 and 4500 rads and wanted to include hyperthermia treatment. Hyperthermia treatment required insertion of interstitial microwave antennae so that heat treatment was terminated within one hour before the implants were inserted and was initiated within one hour after the implants were removed. The attending physician was informed by the licensee's's staff that the implants would have to be removed at unreasonable times in order to fall within the attending physician's desired dose range. The attending physician then agreed to give 4628 rads so that the second hyperthermia treatment could be given at a more reasonable time. Since the actual delivered dose fell within the attending physician's initial range, the licensee does not foresee any adverse effects for Patient E.

Cause or Causes—It was determined that the cause of the misadministration was an input error into the treatment planning computer. Specifically, the source calibration factor was in non-Systeme Internationale (SI) units (non-metric), however, the computer was set to receive the data in SI units and the setting was not changed.

Actions Taken to Prevent Recurrence

Licensee—The licensee's corrective action was to include the calibration factor that is used during treatments in their records for Implant Source Inventory—Source Type Characteristics so that the licensee can verify that the proper factors are used.

NRC—An NRC Region I inspector conducted an inspection of the incident on August 5, 1992, to determine the circumstances associated with the misadministration. The inspector's findings were in agreement with the licensee concerning the cause of the misadministration. The inspector

determined that the licensee's corrective actions were adequate to prevent recurrence. Inspection findings regarding the misadministration are documented in Inspection Field Notes approved September 9, 1992.

* * * * *

92–10 Extremity Overexposure of a Radiographer at MQS Inspection, Inc., Field Site in Trenton, Michigan

One of the AO reporting guidelines notes that an exposure of the feet, ankles, hands, or forearms of any individual to 375 rem or more of radiation can be considered an abnormal occurrence.

Date and Place—July 6, 1992; a temporary radiography field site in Trenton, Michigan.

Nature and Probable Consequences—On July 6, 1992, a licensee radiographer was assigned to radiograph various pipes at a construction site. Radiography is a non-destructive testing technique which uses a sealed radiation source to make X-ray-like images of heavy metal objects.

The configuration of this job required that the radiography exposure device (camera) be suspended 20 feet above the floor. The radiation source is exposed using a remote cable to make the film image and then is retracted into the shielded camera. After an exposure, the radiographer used an aerial platform to reach the camera. He performed a radiation survey as he approached to assure that the source was in the shield. The radiographer was wearing his audible alarm radiation measuring device, but it was turned off.

The radiographer then moved the camera to reach the camera port to lock the radiation source inside. When he removed the tube which guides the source, he discovered the radiation source was exposed about 4 inches outside the camera. The source had apparently shifted into the unshielded position when the radiographer moved the camera to lock it. The source was locked into place in its exposed condition. The radiographer immediately returned to ground level, but later returned to the camera to unlock it so that the radiation source would be retracted into its shield.

The incident was subsequently reenacted by the licensee's Radiation Safety Officer and NRC inspectors to evaluate the radiation exposure received by the radiographer. The calculation by the Radiation Safety Officer, based on a series of reenactments, indicated a minimum 440 rem exposure to the individual's hand. NRC inspectors estimated that the dose was about 880 rem. The radiation measuring device worn by the worker indicated a whole body radiation exposure of about 250 millirem.

The worker's hand was evaluated and monitored by medical radiation specialists at an area medical center. No short-term physical changes to the skin of the hand were observed.

The NRC limit was extremity exposures is 18.75 rem in a calendar quarter. Therefore, the reenactment showed that the exposure received was substantially over the limit. The whole body radiation exposure was within the NRC limit of 3 rem in a calendar quarter.

Cause or Causes—The overexposure occurred as a result of the failure of the radiographer to use an audible alarm exposure measuring device as required by NRC regulations. The locking mechanism allowed the source to be locked in place while it was still exposed.

The radiographer was wearing an audible alarm device required by the NRC for radiography work, but the device was turned off. The device had been turned off to conserve battery power while the radiographer was doing paperwork, but had not been turned back on for the remainder of the day. Use of an operable alarm device could have avoided or minimized the overexposure.

Actions Taken to Prevent Recurrence

Licensee—The licensee alerted its staff to the potential problem with the locking mechanism of this type of radiography camera. It also provided additional training on the use of the required audible alarm radiation devices and included verifying that the devices are turned on during routine internal audits of radiography activities. The radiographer was restricted indefinitely from further work with radioactive materials.

NRC—The NRC Region III conducted a special inspection of the licensee's activities on July 8–10, 1992. The inspection identified three violations of NRC requirements associated with the overexposure incident: (1) The extremity exposure in excess of the 18.75 rem limit for a calendar quarter; (2) failure of the radiographer to wear an operable audible radiation monitoring device; and (3) failure to perform an adequate radiation survey of the radiography camera in that the radiographer did not survey the full circumference of the camera. The first two violations were classified as a Severity Level I problem, and the third as a Level IV violation (on a scale in which Severity Levels I through V are the most and least significant, respectively). On October 9, 1992, a $5,000 fine was proposed for the first two violations. No fine was proposed for the third violation. On November 2, 1992, the licensee paid the civil penalty

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92–11 Medical Therapy Misadministration at the Medical Center of Delaware, Incorporated, in Wilmington, Delaware

One of the AO reporting guidelines notes that a therapeutic exposure to a part of the body not scheduled to received radiation can be considered an abnormal occurrence.

Date and Place—August 11, 1992; The Medical Center of Delaware, Incorporated; Wilmington, Delaware.

Nature and Probable Consequence—On August 12, 1992, the NRC Region I office was notified by telephone by the licensee's radiation safety office that a therapeutic misadministration involving a cobalt-60 teletherapy unit occurred on August 11, 1992.

The physician's written directive called for 3015 rads in 15 fractions to be delivered to the central area of the pelvic region with the teletherapy machine set up in a fixed modality. During the 14th fraction, the radiation therapy technologist (RTT) did not ensure that the teletherapy machine was set in the fixed modality and started the treatment. The previous patient had received treatment in the rotational modality and the setting of the machine was not changed. The patient received a total of 160 rads to the pelvic treatment area instead of the prescribed 200 rads. In addition, the licensee estimates that the patient received an estimated dose of 80 to 110 rads to the left side of the pelvis outside of the treatment area and between 60 to 70 rads to the right side of the pelvis outside of the treatment area. The licensee has determined that the patient will not suffer any adverse effects in the areas that received an unintended radiation dose. The licensee will increase the prescribed dose for the 15th fraction to make up for the underdosing during the 14th fraction.

Cause or Causes—It was determined that the cause of the misadministration was the failure of the licensee to follow the department's Quality Management (QM) Program. The licensee's QM Program calls for two RTTs to be present when a patient is being set up to ensure that the setup is done properly. The first RTT did not ensure that the setup was done correctly and the second RTT was out of the department getting another patient.

Actions Taken to Prevent Recurrence

Licensee—The licensee's corrective action was to provide a training session to all RTTs on the requirements of the Quality Management Program.

NRC—An NRC Region I inspector conducted an inspection on November 19, 1992, to determine the circumstances associated with the misadministration. The inspection findings are still under review by the NRC, and enforcement action is under consideration.

* * * * *

Dated at Rockville, MD this 5th day of January, 1993.

For the Nuclear Regulatory Commission.

Samuel J. Chilk,

Secretary of the Commission.

[FR Doc. 93–474 Filed 1–8–93; 8:45 am]

BILLING CODE 7590–01–M

Documents Containing Reporting or Recordkeeping Requirements: Office of Management and Budget Review

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of the Office of Management and Budget review of information collection.

SUMMARY: The Nuclear Regulatory Commission (NRC) has recently submitted to the Office of Management and Budget (OMB) for review the following proposal for the collection of information under the provisions of the Paperwork Reduction Act (44 U.S.C. chapter 35).

1. Type of submission, new, revision, or extension: Extension.

2. The title of the information collection: 10 CFR part 33—Specific Domestic Licenses of Broad Scope for Byproduct Material.

3. The form number if applicable: Not applicable.

4. How often the collection is required: New applications may be submitted at any time. Renewal applications are submitted every five years.

5. Who will be required or asked to report: Persons applying for or holding an NRC license for broad scope use of radioactive byproduct material. Applicants and licensees are primarily medical institutions, colleges, universities, government agencies, and large private companies engaged in broad educational, research, and development activities.

6. An estimate of the number of responses: 120.

7. An estimate of the total number of hours needed to complete the requirement or request: Twenty hours per submittal. The total industry burden is 2,400 hours.

8. An indication of whether section 3504(h), Public Law 96–511 applies: Not applicable.

9. Abstract: 10 CFR part 33 specifies requirements for applying for and being granted licenses authorizing broad scope use of radioactive byproduct material. The information submitted is reviewed by NRC to determine whether the applicant has adequate equipment, facilities, procedures, training, and experience to safely use radioactive material.

Copies of the submittal may be inspected or obtained for a fee from the NRC Public Document Room, 2120 L Street, NW. (Lower Level), Washington, DC.

Comments and questions may be directed by mail to the OMB reviewer: Ronald Minsk, Office of Information and Regulatory Affairs (3150–0015), NEOB–3019, Office of Management and Budget, Washington, DC 20503.

Comments may also be communicated by telephone at (202) 395–3084.

The NRC Clearance officer is Brenda Jo. Shelton, (301) 492–8132.

Dated at Bethesda, Maryland, this 30th day of December 1992.

For the Nuclear Regulatory Commission.

Gerald F. Cranford,

Designated Senior Official for Information Resources Management.

[FR Doc. 93–472 Filed 1–8–93; 8:45 am]

BILLING CODE 7590–01–M

OFFICE OF MANAGEMENT AND BUDGET

[Issuance of Policy Letter 92–5]

Office of Federal Procurement Policy; Past Performance Information

AGENCY: Executive Office of the President, Office of Management and Budget, Office of Federal Procurement Policy (OFPP).

ACTION: Final Issuance of OFPP Policy Letter 92–5.

SUMMARY: Policy Letter 92–5 establishes policies that require Executive agencies to prepare evaluations of contractor performance on all contracts over $100,000 and to specify past performance as an evaluation factor in solicitations for offers for all competitively negotiated contracts expected to exceed $100,000. The Policy Letter also provides requirements to help assure that confidentiality and fairness concerns are addressed in the collection and use of past performance information (PPI).

FOR FURTHER INFORMATION CONTACT: Charles W. Clark, OFPP, Office of Management and Budget, Washington, DC 20503, (202) 395–6805.

SUPPLEMENTARY INFORMATION: A draft of Policy Letter 92–5 was published in the **Federal Register** for review and public comment on December 6, 1991 (56 FR 63988). Comments were received in response to the **Federal Register** notice from 23 Government and 22 private organizations. All comments were reviewed and, where warranted, changes have been made in the final Policy Letter. The main issues and concerns raised during the comment period are summarized below:

1. *Purpose.* Comments from one Federal agency recommended that the Policy Letter be expanded to include the use of past performance information for "general procurement management purposes." Comments from several private organizations requested that the Policy Letter be limited to addressing the use of Past Performance Information (PPI) in responsibility determinations and sources selections. This latter recommendation was accepted. If agencies continue to believe after the issuance of this Policy Letter that further policy guidance is needed on PPI, OFPP will consider supplementing the Policy Letter.

2. *Definitions.* A definition of "contractor" was added at the request of several private organizations, and an expanded definition of PPI has been provided. The definition of PPI was taken, in part, from Defense Logistic Agency (DLA) Solicitation No. DLA 200–91–R–0068, March 29, 1991. DLA's actions under this solicitation were protested to the General Accounting Office (GAO). The Comptroller General upheld DLA's actions in *CORVAC, Inc.*, B–244766, 91–2, CPD, ¶ 454. This decision and the DLA solicitation provide useful background information on the use of past performance.

3. *Distinction Between Responsibility Determinations and Evaluation Factors.* Several Federal agencies recommended that the Policy Letter made a clear distinction between using PPI for responsibility determinations versus as a source selection factor. The Policy Letter provides that PPI is to be considered (a) in responsibility determinations pursuant to Federal Acquisition Regulation (FAR) 9.1; and (b) in source selections for competitively negotiated contracts expected to exceed $100,000 (except where the contracting officer determines that such use is not appropriate). CORVAC, referenced in Paragraph 2 above, and the cases cited therein

discuss the distinction between "technical acceptability" (as an evaluation factor) and "responsibility."

4. *PPI Systems.* Many Federal agencies commented that the provisions in the draft Policy Letter that would have required agencies to establish "formal systems" for compiling and using PPI were unnecessary and impractical. The provision was generally interpreted as requiring agencies to fund the establishment of automated systems and central data banks. The agencies indicated in their comments that they did not have funds for this purpose. While automated systems may be appropriate for major contracting centers or in some agencies, the Policy Letter has been changed to only require that PPI be used and that existing systems be reviewed to determine if they can be consolidated. Agency procedures for obtaining and using PPI (including systems, if any) must still comply with the fairness and openness provisions of Paragraph 7. of the Policy Letter.

5. *Government/Industry Data Exchange Program (GIDEP).* Two agencies stated that it was not necessary to issue the Policy Letter as it duplicated OFPP Policy Letter 91–3, Reporting Nonforming Products, April 15, 1991 (56 FR 15108). Policy Letters 91–3 and 92–5 are not duplicative. Policy Letter 91–3 requires agencies to exchange information about nonconforming products through GIDEP. Policy Letter 92–5 requires contracting officers to (a) evaluate a contractor's performance on contracts over $100,000, and (b) use past performance information in making responsibility determinations and, where feasible, as a source evaluation factor in competitively negotiated procurements over $100,000. GIDEP helps eliminate instances where agencies or contractors acquire products and materials previously identified as nonconforming by other agencies. The use of PPI helps eliminate instances where agencies might, unknowingly, hire a contractor with a poor performance record.

6. *De Facto Suspensions or Debarments.* Some agencies said that the compilation and use of past performance information would lead to the de facto suspension or debarment of contractors. Policy Letter 92–5 specifies, in Paragraph 4., that the Policy Letter is not intended to supplant contracting officials' judgments in initiating or conducting debarment and suspension proceedings under FAR 9.4. Even though PPI may be used in debarment or suspension proceedings, the Policy Letter does not waive or change any of the due process requirements presently provided with suspension and debarment proceedings. To the contrary, the contractor notification and other provisions contained in Paragraph 7, as well as other parts of the Policy Letter, should help prevent de facto suspensions and debarments.

7. *Specification of Evaluation Factors.* Several private organizations suggested that OFPP specify in the Policy Letter the specific performance evaluation factors and subfactors that agencies would be required to consider in evaluating contractors. Several Federal agencies recommended that OFPP not define rating factors. Rating factors have not been defined as evaluations will vary depending upon the nature of the contract and the circumstances surrounding the contractor's performance. Evaluation factors under fixed price supply contracts will be different, for example, than factors under a cost-type service contract. Instead of listing the evaluation factors, the Policy Letter specifies in Paragraph 6.c. that past performance should be used as an evaluation factor in solicitations for competitively negotiated contracts. It is within the agency's discretion to determine what aspects of performance are important for a particular contract and the relative weight that these factors will be given.

8. *Confidentiality of PPI.* The most frequent comment received on the proposed Policy Letter was that OFPP should make a determination in the Policy Letter that past performance information should not be released to any private party without a contractor's consent. Several private organizations as well as Government agencies asked OFPP to make a determination in the Policy Letter that past performance information is not susceptible to being released under a Freedom of Information Act (FOIA) request. Agencies and private sector individuals alike view past performance information as "privileged" or "pre-decisional," and therefore not subject to FOIA requests. OFPP cannot make a general determination that PPI is exempt from FOIA inquiries. Each FOIA inquiry must be evaluated on its own merits and considerations must be given to the nature of the information to be released as well as the purpose for which the information is currently being used.

9. *Newly Established Firm.* Several commentors requested that OFPP define newly established firm in the Policy Letter. This suggestion was not adopted, as there are no criteria that would be generally applicable. In some fields, for example, a newly established firm may have been in existence for three years and completed very little business. In other situations, a new firm could have been in business for only one year and completed several contracts. The intent of the Policy Letter with respect to newly established firms is to specifically state that a firm cannot be prohibited from competing for a Government contract policy because of a lack of performance history, particularly if the firm is adequately funded and has experienced, reputable key personnel. However, if past performance is specified in the solicitation for offers as an award factor, a firm with a proven performance history generally would be preferred over a firm without a performance history, if all other factors were equal.

10. *Review Process.* Many Federal agencies stated that the requirement in the Policy Letter to provide copies of contractor evaluations to the contractors would lead to disputes and lengthen the contracting process. These agencies indicated that if performance evaluations were shared with contractors, the evaluators would not be candid and the evaluations would be bland and not very meaningful. OFPP believes that this is a problem with the evaluators and not with the requirement to share evaluations. Candid discussions between Government contracting officials and contractors will serve to improve both contractor performance and administration of the contracts by Government contracting officials. There is no requirement in the Policy Letter that contracting officials obtain the concurrence or approval of the contractor regarding the content of the evaluation. The ultimate content of the evaluation lies within the discretion of the contracting agency and normally would not be subject to dispute, unless the evaluation were to form the basis for a contract claim as defined by the Contract Disputes Act and FAR implementing regulations.

11. *Evaluation of Subcontractor Performance.* Several private concerns stated that a contractor's performance is often related to subcontractor performance and the prime contractor should not receive a poor performance evaluation because of the failure of a subcontractor to perform. Provisions to this effect were not included in the Policy Letter. The Government lacks privity of contract with the subcontractor. Moreover, the Government generally looks to the prime contractor to assure that subcontractors perform. A prime contractor's ability to select subcontractors that perform is indicative of the contractors' management ability.

12. *Relationship to OFPP Policy Letter 91–2, Service Contracting.* Two private organizations requested that the relationship be clarified between this Policy Letter (Policy Letter 92–5) and Policy Letter 91–2 (56 FR 15116, April 15, 1991). "Performance-based contracting" as defined in Policy Letter 91–2 means, "structuring all aspects of an acquisition around the purpose of the work to be performed as opposed to either the manner by which the work is to be performed or broad and imprecise statements of work." One of the purposes of performance-based contracting is to permit the quantitative and qualitative measurement of the tasks performed under a contract. Policy Letter 92–5 compliments this purpose by requiring that written evaluations be made of a contractor's performance and that PPI be used in source selections. A major difference between the policy letters is that 91–2 pertains only to service contracting while 92–5 covers contracts for both services and supplies.

13. *General.* Other comments accommodated in the Policy Letter include:

—Deletion of the word "transparency." A number of commentors said they did not understand the meaning of the word. Accordingly, "transparency" has been replaced by "public notice" in Paragraph 7.a.(2) of the Policy Letter.

—Deletion of the reference to "routine reference checks." These words were deleted from Paragraph 7.a.(4) in response to comments that stated that PPI should not be provided to third parties without the contractor's consent.

—Lengthening the time (from three years to six years) that PPI should be retained without being disposed of or updated. Several commentors noted that some contracts run longer than three years, and the retention period should exceed the length of the contract.

—Clarifying that PPI is not limited to prior performance on Government contracts but also includes work performed for private firms. This clarification was made in Paragraph 7.a.(7).

Allan V. Burman,

Administrator.

Policy Letter No. 92–5

To The Heads of Executive Departments and Establishments

Subject: Past Performance Information

1. *Purpose.* This Policy Letter establishes requirements for evaluating contractor performance and for using past performance information in the contractor selection process. The Policy Letter is intended to further the exercise of good business judgment and improve contractor performance.

2. *Authority.* The Policy Letter is issued pursuant to Section 6(a) of the Office of Federal Procurement Policy (OFPP) Act, as amended, 41 U.S.C. 405.

3. *Definitions.*

a. *Executive Agency.* Means an Executive department, and an independent establishment within the meaning of 5 U.S.C. 101, 102, 103(1) and 104(1), respectively.

b. *Contractor.* A contractor is an entity, or in a large company a specific division or unit, identified by a Contractor Establishment Code pursuant to the Federal Acquisition Regulation (FAR) 4.6.

c. *Past Performance Information.* Past performance information is relevant information regarding a contractor's actions under previously awarded contracts. It includes the contractor's record of conforming to specifications and to standards of good workmanship; the contractor's record of containing and forecasting costs on any previously performed cost reimbursable contracts; the contractor's adherence to contract schedules, including the administrative aspects of performance; the contractor's history for reasonable and cooperative behavior and commitment to customer satisfaction; and generally, the contractor's business-like concern for the interest of the customer.

d. *Past Performance Information System.* A past performance information system is an ongoing effort to collect and record past performance information for subsequent use in determining contractor eligibility and selection.

4. *Scope.* This Policy Letter pertains to past performance information as defined above. The Policy Letter does not pertain to procedures used by agencies in assessing performance for purposes of determining fees under award or incentive fee contracts. Similarly, the Policy Letter is not intended to supplant contracting officials' judgments in initiating or conducting debarment and suspension proceedings under Federal Acquisition Regulation (FAR) 9.4. The Policy Letter is applicable to direct Federal procurements, it is not applicable to procurements under grants or cooperative agreements or to procurements made by Government contractors.

5. *Background.* A contractor's past performance record is a key indicator for predicting future performance. A satisfactory performance record is a prerequisite to being determined a "responsible source" pursuant to 41 U.S.C. 403. In addition, FAR 15.605 requires that quality be addressed in every source selection and recognizes past performance as a factor in assessing quality. Several agencies have established policies and procedures for collecting, recording and using past performance information. These practices are extremely important to both the Government and to contractors, and requirements are necessary to help ensure their integrity and fairness. This Policy Letter provides such requirements.

6. *Policy.* It is the policy of the Federal Government that Executive agencies shall:

a. Prepare evaluations of contractors' performance on all new contracts over $100,000. Evaluations shall be made during contract performance, as required for contract administration purposes, and at the time the work under the contract is completed.

b. Use past performance information in making responsibility determinations in both sealed bid and competitively negotiated procurements. Performance information is one factor, among many, that must be considered in making such a determination (see FAR 9.1).

c. Specify past performance as an evaluation factor in solicitations for offers for all competitively negotiated contracts expected to exceed $100,000 except where the contracting office determines that such action is not appropriate. Such determinations shall be in writing and included in the contract file. As an evaluation factor, past performance should be used to assess the relative capabilities of competing offerors and to help assure greatest value source selections.

d. Allow newly established firms to compete for contracts even though they lack a history of past performance.

7. *Responsibilities.*

a. *Heads of Executive Agencies.* In implementing the policies in Paragraph 6, above, Executive agencies shall comply with the following:

(1) *Agency Regulations.* Heads of departments and agencies are responsible for taking all necessary actions to assure effective implementation of these policies, such as disseminating this Letter to appropriate program and other staff, developing implementation strategies and initiating staff training. Since these policies must be implemented in the FAR, agencies should not duplicate the development of implementing procurement regulations being undertaken by the Federal Acquisition Regulatory Councils. However, implementation of these policies in the FAR must be accomplished within the time period specified in Paragraph 8 below, with inclusion in agency solicitations and resulting contracts, as appropriate, to occur immediately thereafter.

(2) *Public Notice.* Regulations developed to implement provisions of this Policy Letter must conform to the publication requirements of Section 22 of the Office of Federal Procurement Policy Act (41 U.S.C. 418(b)) and FAR, Part 1.5.

(3) *Notification to Contractors.* Contractor evaluations shall be provided to the contractor at the time they are completed. Contractors shall be given a minimum of 30 days to discuss any evaluation with the contracting officer or if the contracting officer does the evaluation with the head of the contracting activity. While the ultimate conclusion and content of an evaluation is a decision of the contracting agency, the contractor may submit rebutting statements or additional information at any time. Copies of any such statements shall be appended to the evaluation and included in the contract file.

(4) *Confidentiality of Information.* Upon request, past performance information should be made available to other Federal

procurement activities. However, past performance information about a contractor shall not be provided, without the contractor's consent, to any private party, except where the agency determines that such information must be released pursuant to a Freedom of Information Act request. Additionally, because of the sensitive nature of contractor histories, appropriate management and technical controls should be made a part of any automated system used for tracking contractor performance to assure that only authorized personnel have access to the data.

(5) *Permanency of Information.* Performance information should not be considered a permanent indicator of a contractor's capability. The age and relevancy of the information should be considered at the time it is used. It should not be maintained for more than 6 years without being disposed of or updated.

(6) *Preservation of Contracting Officer's Judgment.* Information about a contractor's performance shall not be used to supplant the judgment of contracting officers in their selection of contractors. Past performance information is, in part, subjective and must be interpreted and considered by the contracting officer within the context of all other available data.

(7) *Obtaining Past Performance Information.* Data on a contractor's performance may be obtained from a variety of sources. Information on prior agency contracts should be available from within the agency. Information on contracts outside the agency may be obtained from past performance assessments made by other contracting activities including private firms. The methods used to obtain past performance information should be tailored to focus on information that demonstrates the quality of performance relative to the size, content, and complexity of the requirements for the instant procurement.

(8) *Using Past Performance Information.* Past performance information should be used to assess risk. Each performance evaluation and risk assessment should consider the number and severity of a contractor's problems, the effectiveness of corrective actions taken, and the contractor's overall work record. The assessment of performance risk should consider the relative merits of the contractor's prior experience and performance as compared to that of other competing offerors.

(9) *Review of Existing Systems.* Existing past performance information systems shall be reviewed to determine if multiple systems can be consolidated, and to ensure compliance with this Policy Letter. Agencies considering the establishment of a past performance information system shall first consider the use of an existing system.

(a) *Special Requirements for Architect/Engineer (A/E) and Construction Contracts.* Agencies shall evaluate construction contractor performance in accordance with FAR 36.201 and A/E contractor performance in accordance with FAR 36.604. Rather than establishing independent systems for maintaining performance evaluation forms—Standard Forms 1420 (Construction Contracts) and 1421 (Architect Engineer Contracts)—agencies are encouraged to use the following existing systems operated by the Corps of Engineers:

—The Construction Contract Appraisal Support System (CCASS) which contains over 15,000 performance appraisals covering approximately 7000 construction firms.

—The A/E Contract Administration Support System (ACASS) which contains 18,000 performance appraisals covering approximately 4,000 A/E firms.

The present point of contact for ACASS is Ms. Judy McGinnis, (503) 326–4910, and for CCAS, Ms. Kem Morrow at the same telephone number.

8. *Federal Acquisition Regulatory Councils.* Pursuant to Subsection 6(a) of the Office of Federal Procurement Policy Act, as amended, (41 U.S.C. 401 *et seq.*), the Federal Acquisition Regulatory Councils shall ensure that the policies established herein are incorporated in the FAR within 210 days from the date this Policy Letter is published in final form in the **Federal Register**. Promulgation of final FAR regulations within that 210 day period shall be considered issuance in a "timely manner" as prescribed in 41 U.S.C. 405(b)."

9. *Effective Date.* This Policy Letter is effective upon issuance.

10. *Information.* Questions or inquiries about this Policy Letter should be directed to Charles W. Clark, Office of Federal Procurement Policy, 725 17th Street, NW., Washington, DC 20503, telephone (202) 395–6803.

Allan V. Burman,

Administrator.

[FR Doc. 93–443 Filed 1–8–93; 8:45 am]

BILLING CODE 3110–01–M

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–31684; File No. SR–NASD–92–35]

Self-Regulatory Organizations; Filing of Proposed Rule Change by National Association of Securities Dealers, Inc. Relating to Margin Requirements

January 4, 1993.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 ("Act"), 15 U.S.C. 78s(b)(1), notice is hereby given that on August 20, 1992,[1] the National Association of Securities Dealers, Inc. ("NASD" or "Association") filed with the Securities and Exchange Commission ("SEC" or "Commission") a proposed rule change. The NASD subsequently filed on December 4, 1992, Amendment No. 1 to the filing which replaced in its entirety the original filing. The proposal as amended is described in Items I, II, and III below, which have been prepared by the NASD. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

[1] Simultaneously with the filing of this proposed rule change, the NASD withdrew its filing SR–NASD–88–50, which was originally proposed to conform the NASD's margin rules with those of the New York Stock Exchange ("NYSE"). *See* discussion *infra* at Item II.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The NASD is herewith filing a proposed rule change to amend Appendix A of Article III, Section 30 of the Rules of Fair Practice by replacing in its entirety the current Appendix A. A summary discussion of the proposed rule change follows. Interested persons may obtain a copy of the complete rule filing and/or the text of the proposed rule change by request to the Office of General Counsel, National Association of Securities Dealers, Inc., 1735 K Street, NW., Washington, DC 20006.

Description of Proposed Rule Change

Section 1

The NASD is proposing to amend section 1 of appendix A to provide that members of the NASD designated to another self-regulatory organization ("SRO") for oversight of the member's compliance with applicable securities laws, rules and regulations, and SRO rules under SEC Rule 17d–2 are exempt from the provisions of appendix A. Under the current provisions of section 1, members of any other national securities exchange are exempt from appendix A. The proposed amendment to section 1 will permit the designated examining authority to apply its own margin rules rather than the rules of another self-regulatory organization, significantly simplifying examinations.

Section 2

Proposed new section 2 consists of definitions relating to options transactions substantially the same as NYSE Rule 700. The definitions will apply to the margin requirements for options transactions set forth in proposed subsection 3(f)(2). NYSE Rule 431(f)(2) (the NYSE's options margin rules) references the definitions in NYSE Rule 700 (part of the NYSE's general options rules). There are no comparable definitions in current Section 4. Current section 2 relating to initial margin requirements will be replaced by proposed Subsection 3(b).

Section 3

Unless stated below, the language of the proposed new section 3 is the same as NYSE Rule 431 in all material respects. Current section 3 is being replaced by proposed subsection 3(f)(1)

with respect to valuation of securities; however, the provision in current Section 3 permitting the NASD to require additional margin in the event of undue concentration is not being replaced. The following describes the provisions of proposed new section 3, and, where applicable, those current provisions of Schedule A which will be replaced:

Subsection 3(a)

Proposed subsections 3(a) (1) through (8) are definitions of general applicability to the new margin rule. There are no comparable definitions in current Section 4.

Subsection 3(b) and 3(c)

Proposed new subsections 3(b) and 3(c) establish initial and maintenance margin requirements and replace section 2, and subsections 4(a) (1) through (3) and 4(a) (5) of current appendix A. Proposed new subsection 3(c) (5) establishes margins for American Stock Exchange ("AMEX") Emerging Company Marketplace securities as approved by the SEC in SR–NASD–92–10.[2]

Subsection 3(d)

Proposed new subsection 3(d) requires members to establish procedures for evaluating customer credit and imposing higher margin than required by the other provisions of proposed section 3. Current subsection 4(b)(3) permits the NASD to require 100% margin for certain securities in certain circumstances; otherwise, there is no comparable provision in Section 4.

Subsection 3(e)(1)

Proposed new subsection 3(e)(1) sets margins at 10% of current market value for convertible securities carried long offset against a short position in the resulting security, and 5% of current market value for long securities when the same security is carried long and short in the same account. Current subsections 4(b) (1) and (2) require 10% in each case.

Subsection 3(e)(2)(A)

Proposed new subsection 3(e)(2)(A) requires margins on obligations of the United States ranging from 1% to 6%, based on times to maturity ranging from less than 1 year to 20 years or more, respectively. Current subsection 4(8)(i) imposes margins ranging from ½% to 3% for maturities of less than 1 year up to 10 years, respectively, and current Subsection 4(7) requires margin at 5% for maturities greater than 10 years.

Subsection 3(e)(2)(B)

Proposed new subsection 3(e)(2)(B) sets margins for "all other exempted securities" other than obligations of the United States at the greater of 15% of the current market value or 7% of the principal amount of the obligation. Current Subsection 4(6) requires 25% and 15% respectively, whichever is lower.

Subsection 3(e)(2)(C)

Proposed new subsection 3(e)(2)(C) sets margins for "nonconvertible corporate debt securities" at the greater of 20% of the current market value or 7% of the principal amount, except for certain mortgage related securities for which the margin is 5% of the current market value. There is no comparable provision in section 4 currently. However, subsection 4(a) requires margin of 25% of the market value of all securities long in the account, and subsection 4(a)(8)(ii) permits the Association to establish lower requirements upon application.

Subsection 3(e)(2)(D)

Proposed new subsection 3(e)(2)(D) permits members to clear and carry "basket transactions" for members who are market makers at margin rates satisfactory to the parties, provided the margin is adequate to cover all real and potential risks. This Subsection also permits the carrying member to take a charge to net worth when computing net capital for any margin deficiency in the account. This provision differs slightly from the NYSE's rule because the NYSE requires the computation of net capital under this Rule 325, while the NASD's proposed rule specifies the computation of net capital under SEC Rule 15c3–1. This provision replaces current section 12.

Subsection 3(e)(2)(E)(i)

Proposed new subsection 3(e)(2)(E)(i) permits members to use accrued interest as an offset against maintenance margin requirements. This provision will replace current Section 15 which limits the crediting of accrued interest to interest in government securities.

Subsection 3(e)(2)(E)(ii)

Proposed new subsection 3(e)(2)(E)(ii) provides that the NASD may permit lower margin requirements upon written application. This provision will replace current Subsection 4(a)(8)(ii).

Subsection 3(e)(2)(F)

Proposed new subsection 3(e)(2)(F) provides that in cash transactions with customers for issued exempted securities in a cash account, full payment must be made promptly; otherwise, a deposit shall be required as if it were a margin transaction. Transactions with members or non-member broker/dealers in issued exempted securities however, do not require margin. This provision replaces current Subsection 6(a).

Subsection 3(e)(3)

Proposed new subsection 3(e)(3) permits accounts in which a partner or stockholder of the carrying organization has an interest, to maintain margin according to section 3 for all other participants in the account with respect to such interest as if such interest were in a separate account. There is no comparable provision in current appendix A.

Subsection 3(e)(4)

Proposed new subsection 3(e)(4) exempts international arbitrage accounts of non-member foreign broker/dealers from the requirements of appendix A; however, any deficiency between equity and required margin under appendix A must be charged against the member's net capital. There is no comparable provision in current appendix A.

Subsection 3(e)(5)

Proposed new subsection 3(e)(5) permits a member to carry the account of a market maker or specialist on the margin provided for under the rule, or, as an option, on a margin basis satisfactory to both parties, provided the carrying member takes a deduction against net capital for any deficit below the required margin. This provision, along with proposed subsection 3(e)(2)(D) and 3(e)(6), replaces current Section 12.

Subsection 3(e)(6)

Proposed new subsection 3(e)(6) permits a member to carry the proprietary account of another broker/dealer on a margin basis satisfactory to the parties and in compliance with Federal Reserve Board Regulation T. The provision also permits the member to take a deduction against net capital rather than require margin from the broker/dealer, provided, the account is not in deficit on equity positions. This provision, along with proposed new subsection 3(e)(2)(D) and 3(e)(5) replaces current Section 12.

Subsection 3(e)(7)

Proposed new subsection 3(e)(7) permits members to establish "non-purpose credit" accounts for customers. The term "non-purpose credit" is defined by reference to § 220.2(u) of

[2] Securities Exchange Act Release No. 30703 (May 14, 1992), 57 FR 21684 (May 21, 1992).

Regulation T. There is no comparable provision in current appendix A.

Subsection 3(e)(8)

Proposed new subsection 3(e)(8) establishes margin requirements for "shelf registered," "control" and "restricted" securities. There is no comparable provision in current appendix A.

Subsection 3(f)(1)

Proposed new subsection 3(f)(1) provides that active securities are to be valued at current market prices, and other securities are to be valued after considering liquidation value, price volatility and market liquidity. This provision replaces current section 3.

Subsection 3(f)(2)(D)(i) through 3(f)(2)(K)

Proposed new subsections 3(f)(2)(D)(i) through 3(f)(2)(K) establish margin requirements for options. These provisions typically require margin in excess of 100% of the current market value of any short option. These provisions replace current subsection 4(a)(4), 4(a)(8)(vi) and section 7.

Subsection 3(f)(3)

Proposed new subsection 3(f)(3) provides that the margin required for securities "when issued" is the same as if the security were issued. This provision replaces current section 5.

Subsections 3(f)(4) and 3(f)(5)

Proposed new subsections 3(f)(4) and 3(f)(5) permit the consolidation of any guaranteed account with another account, or the consolidation of any two accounts of a customer, for margin purposes, provided the guarantee or consolidation is agreed to in writing. These provisions replace current sections 8 and 9

Subsections 3(f)(6) and 3(f)(7)

Proposed subsections 3(f)(6) and 3(f)(7) provide that members should collect required margin as quickly as possible and not permit customers routinely to meet Regulation T margin calls through the liquidation of account positions. These provisions replace current sections 10 and 13.

Subsection 3(f)(8)

Proposed new subsection 3(f)(8) provides that the Association may establish higher margin requirements than otherwise required by proposed new section 3. Current subsection 4(b)(3) is comparable to this provision. Proposed new subsection 3(f)(8) also establishes margin requirements for "day traders."

Subsection 3(f)(9)

Proposed new subsection 3(f)(9) provides that members may not permit customers to "free ride" by effecting transactions in cash accounts where the cost of the security is met by the sale of the same securities. There is no comparable provision in current section 4.

Other Changes

Current sections 11 and 14, relating to recordkeeping requirements and the definition of "margin account," respectively, are being eliminated as redundant of other provisions. Recordkeeping requirements are adequately covered by the current SEC rules and the proposed new NASD rules adequately define the terms necessary for interpretation of the rule.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the NASD included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The NASD has prepared summaries, set forth in sections (A), (B), and (C) below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

The NASD is proposing to amend Article III, Section 30, Schedule A of the Rules of Fair Practice to closely conform the NASD's margin rules to those of the NYSE by deleting the current provisions of appendix A and replacing them with rule language substantially identical to the NYSE margin rules.

In November 1988 the NASD filed a proposed rule change, SR-NASD-88-50 ("88-50"), with the SEC to amend appendix A to Article III, section 30 of the Rules of Fair Practice ("Appendix A") in order to make it consistent with the then-recently approved amendments to the NYSE's margin rules (NYSE Rule 431). While the proposed rule change was pending at the SEC, the NYSE again amended its margin rules. The NASD determined to further amend appendix A to closely conform the provisions of appendix A to the amended NYSE margin rules.[3]

Currently, sections 2 and 4 of appendix A provide for initial and minimum margin to be deposited and maintained under rules and formulas which are similar to those of the NYSE, but which differ in several respects. For instance, current section 4 does not require members to evaluate the credit of customers or to establish higher margin requirements for securities or customers based on such evaluation. In addition, current Section 4 permits lower margins to be maintained on U.S. Government securities. Finally, current section 4 does not permit members to establish "non-purpose credit" accounts for customers, does not establish margin requirements for shelf registered, control or restricted securities, or for "day traders." Each of these differences, as well as the others, are addressed in the proposed amendment to appendix A by conforming the NASD's margin rules to those of the NYSE.

The NASD believes that the proposed rule change is consistent with the provisions of section 15A(b)(6) of the Act[4] in that making the NASD's margin rules consistent with those of the NYSE will foster coordination in regulating, clearing, settling and facilitating transactions in securities by providing for a single uniform margin scheme and reducing confusion among customers dealing with NYSE and non-NYSE-member firms.

B. Self-Regulatory Organization's Statement on Burden on Competition

The NASD does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act, as amended.

C. Self-Regulatory Organization's Statement of Comments on the Proposed Rule Change Received from Members, Participants, or Others

Written comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 35 days of the date of publication of this notice in the **Federal Register** or within such longer period (i) as the Commission may designate up to 90 days of such date if it finds such

[3] In addition, on April 1, 1992, the Executive Committee of the NASD Board of Governors approved an amendment to the current Appendix A to provide margin rules for securities which are listed on "incubator" or "emerging company" exchanges such as the AMEX's Emerging Company Marketplace. SR-NASD-92-10 was filed with the SEC on April 2, 1992, and approved by the SEC on May 14, 1992. The proposed amendments to Appendix A include the provisions approved by the SEC in SR-NASD-92-10.

[4] 15 U.S.C. 78o-3 (1988).

longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

A. By order approve such proposed rule change, or

B. Institute proceedings to determine whether the proposed rule change should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing. Persons making written submissions should file six copies thereof with the Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington DC 20549. Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room. Copies of such filing will also be available for inspection and copying at the principal office of the NASD. All submissions should refer to the file number in the caption above and should be submitted by [insert date 21 days from the date of publication].

For the Commission, by the Division of Market Regulation, pursuant to delegated authority, 17 CFR 200.30–3(a)(12).

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 93–495 Filed 1–8–93; 8:45 am]

BILLING CODE 8010–01–M

[Release No. 34–31688; File No. SR–NYSE–92–31]

Self-Regulatory Organizations; Filing of Proposed Rule Change by the New York Stock Exchange, Inc. Relating to Organizations Controlled or Guaranteed by Members or Member Organizations

January 5, 1993.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 ("Act"), 15 U.S.C. 78s(b)(1), notice is hereby given that on October 16, 1992, the New York Stock Exchange, Inc. ("NYSE" or "Exchange") filed with the Securities and Exchange Commission ("Commission") the proposed rule change as described in Items I, II and III below, which Items have been prepared by the self-regulatory organization. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The changes consist of the amendment of Rule 321 ("Formation of Corporate Affiliates"), rescission of Rules 322 ("Guaranteed Corporate Subsidiaries") and 324 ("Formation of Associated Partnerships"); adoption of new Rule 322 ("Guarantees by, or Flow Through Benefits for Members or Member Organizations"); and amendments to Rules 113 ("Specialists' Public Customers"), 122 ("Orders With More Than One Broker"), 342 ("Offices—Approval, Supervision and Control"), 346 ("Limitations—Employment and Association with Members and Member Organizations"), 416 ("Questionnaires and Reports") and 476 ("Disciplinary Proceedings Involving Charges Against Members, Member Organizations, Allied Members, Approved Persons, or Employees").

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The self-regulatory organization has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

(a) Purpose

Current NYSE Rules 321, 322 and 324 prescribe the requirements which must be followed by a member or member organization in order to obtain Exchange approval to form and operate any entity (corporate affiliate, guaranteed subsidiary or associated partnership) which they will control that is engaged in a securities or kindred business.

The rules were originally adopted in the late 1960s in a very different environment, *e.g.*, before public ownership of securities firms and the advent of sophisticated corporate structures, diversification of product and business lines and the internationalization of our business. Rule 321 was intended to protect member organizations' capital by segregating out what were then deemed more risky or speculative activities such as underwriting, advisory, and securities brokerage dealings on a principal basis. Under this Rule, member organizations are required, among other things, to own 40 percent of the total capitalization, own all of the voting stock and are prohibited from guaranteeing the liabilities and obligations of these corporate affiliates. Directors and key officers of the entity must be associated with the member organization and together with registered representatives must be approved by the Exchange.

Corporate entities controlled by member organizations formed to do what were considered more traditional brokerage activities (foreign and domestic) are required to be wholly-owned and guaranteed subsidiaries under Rule 322. Such entities and their associated persons are subject to the Constitution and Rules of the Exchange to the same extent as are member organizations. Such entities may engage in an agency business only (may not transact business on a principal basis). Entities formed under Rule 324 are subject to virtually the same provisions as entities formed under Rule 322 except that Rule 324 applies to associated partnerships. Broker-dealers required to be formed under these Rules 321, 322 and 324 must introduce customer accounts to their parent member organizations as they are not permitted to carry customer accounts on their books.

The original concept of these rules and many of their restrictive requirements are outdated and no longer serve a valid regulatory purpose. The rules' requirements inhibit member organizations management of their assets, organizational structure and business activities and impose significant impediments to their pursuit of legitimate business activities. In addition, the existing rules, by their terms, apply only to direct subsidiaries. Member organizations having a holding company structure have been able to avoid the rules' restrictions. According to the NYSE, member organizations, however, should not be forced to choose between forming a holding company and incurring the attendant expenses or refraining from engaging in legitimate business activities.

The proposed rule changes will allow member organizations the flexibility to structure their affiliates in a manner that would permit diversification and keep

pace with the competitive environment within the industry, while also maintaining appropriate regulatory safeguards.

Proposed amended Rule 321 will require prior written approval whenever a member or member organization controls another person, within the meaning of Rule 2,[1] who is engaged as a broker or dealer in securities. In addition, the proposed rule change deletes many provisions relating to capitalization, structure (*e.g.*, classes of stock; fixed interest by members and allied members) and content and submission of documents (*e.g.*, charter, certificate of incorporation and bylaws) by affiliates which are outdated and/or are not currently required of member organizations. Current Rules 322 and 324 are proposed to be rescinded in view of proposed amendments to Rule 321 and proposed adoption of new Rule 322.

With intent to protect members and member organizations' financial integrity and provide the Exchange with the means to monitor impact upon capital, proposed new Rule 322 will require prior written notice whenever a member or member organization guarantees or assumes or endorses the obligations and/or liabilities of another person. The written notice must include a statement with respect to financial and operational impact upon the member or member organization. Further, members and member organizations will be required to provide the Exchange with access to books and records whenever requested. Broker-dealers subject to Rule 322 will have to file FOCUS reports and non-broker-dealers would submit other financial statements specified by the Exchange.

In order to effect these proposed rule changes, and to provide for consistency in the rules, changes are necessary to other rules (Rules 113 "Specialists' Public Customers," 122 "Orders With More Than One Broker" and 416 "Questionnaires and Reports") that also apply to affiliates of members and member organizations. Further, amendments to Rule 342 will define the term foreign branch office and provide that all foreign branch office personnel of member organizations will be subject to the Exchange Constitution and Rules to the same extent as personnel of member organizations. Amended Rule 342 also provides that a foreign branch office shall continue to be treated as any other branch of the member organization for regulatory purposes and that all obligations and liabilities shall continue to be assumed or guaranteed by the parent member or member organization. Proposed amendments to Rule 476 clarify and codify the Exchange's authority to impose sanctions against all persons subject to Exchange jurisdiction (including affiliates) upon a finding of guilt in a proceeding under Rule 476.

(b) Statutory Basis

The proposed rule changes are consistent with the requirements of the Act and the rules and regulations thereunder applicable to the Exchange in that they are designed, in accordance with section 6(b)(1) of the Act, to enhance the Exchange's capacity to carry out the purposes of the Act and to compel and enforce compliance by its members and member organizations and their associated persons with the provisions of the Act, the rules and regulations thereunder and the rules of the Exchange.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange believes that the proposal does not impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

Comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 35 days of the publication of this notice in the **Federal Register** or within such other period (i) as the Commission may designate up to 90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

(A) By order approve the proposed rule change, or

(B) Institute proceedings to determine whether the proposed rule change should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views and arguments concerning the foregoing. Persons making written submissions should file six copies thereof with the Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549. Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying at the Commission's Public Reference Section, 450 Fifth Street, NW., Washington, DC 20549. Copies, of such filing will also be available for inspection and copying at the principal office of the NYSE. All submissions should refer to File No. SR–NYSE–92–31 and should be submitted by February 1, 1993.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 93–484 Filed 1–8–93; 8:45 am]

BILLING CODE 8010-01-M

[1] Rule 2 defines "control," in pertinent part, as the power to direct or cause direction of the management or policies of a person. There is a presumption of control where a person (i) has the right to vote 25% or more of the voting securities, or (ii) is entitled to 25% or more of the net profits.

Self-Regulatory Organizations; Midwest Stock Exchange, Inc.; Application for Unlisted Trading Privileges in one Over-the-Counter Issue and to Withdraw Unlisted Trading Privileges in an Over-the-Counter Issue

January 4, 1993.

On December 22, 1992, the Midwest Stock Exchange, Inc. ("MSE") submitted an application for unlisted trading privileges ("UTP") pursuant to section 12(f)(1)(C) of the Securities Exchange Act of 1934 ("Act") in the following over-the-counter ("OTC") security, *i.e.*, a security not registered under Section 12(b) of the Act.

File No.	Symbol	Issuer
7–9868	MTCEF	MTC Electronic Technologies Co. LTD. Common Stock No par value

The above-referenced issue is being applied for as a replacement for the following security, which forms a portion of the Exchange's program in which OTC securities are being traded pursuant to the granting of UTP.

The MSE also applied to withdraw UTP pursuant to section 12(f)(4) of the Act for the following issue:

File No.	Symbol	Issuer
7–9869	FOFF	50-Off Stores, Inc. Common Stock. $.01 par value.

Withdrawal of the Common Stock of 50-Off Stores, Inc. is requested due to lack of trading activity.

Comments

Interested persons are invited to submit, on or before January 25, 1993, written comments, data, views and arguments concerning this application. Persons desiring to make written comments should file three copies with the Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549.

Commentators are asked to address whether they believe the requested grant of UTP as well as the withdrawal of UTP would be consistent with section 12(f)(2), which requires that, in considering an application for extension or withdrawal of UTP in an OTC security, the Commission consider, among other matters, the public trading activity in such security, the character of such trading, the impact of such extension on the existing markets for such security, and the desirability of removing impediments to and the progress that has been made toward the development of a national market system.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 93–496 Filed 1–8–93; 8:45 am]

BILLING CODE 8010–01–M

Self-Regulatory Organizations; Midwest Stock Exchange, Inc.; Application for Unlisted Trading Privileges in one Over-the-Counter Issue and to Withdraw Unlisted Trading Privileges in an Over-the-Counter Issue

January 4, 1993.

On November 17, 1992, the Midwest Stock Exchange, Inc. ("MSE") submitted an application for unlisted trading privileges ("UTP") pursuant to section 12(f)(1)(C) of the Securities Exchange Act of 1934 ("Act") in the following over-the-counter ("OTC") security, *i.e.*, a security not registered under section 12(b) of the Act.

File No.	Symbol	Issuer
7–9868	NNCXF	Newbridge Network Corporation.

File No.	Symbol	Issuer
		Common stock No par value

The above-referenced issue is being applied for as a replacement for the following security, which forms a portion of the Exchange's program in which OTC securities are being traded pursuant to the granting of UTP.

The MSE also applied to withdraw UTP pursuant to section 12(f)(4) of the Act for the following issue:

File No.	Symbol	Issuer
7–9867	CUSA	Compusa Inc. Common stock No par value

A replacement issue is being requested as the common stock of Compusa Inc. has been listed on the NYSE, rendering it ineligible for the OTC/UTP program.

Comments

Interested persons are invited to submit, on or before January 25, 1993, written comments, data, views and arguments concerning this application. Persons desiring to make written comments should file three copies with the Secretary, Securities and Exchange Commission, 450 Fifth Street NW., Washington, DC 20549.

Commentators are asked to address whether they believe the requested grant of UTP as well as the withdrawal of UTP would be consistent with section 12(f)(2), which requires that, in considering an application for extension or withdrawal of UTP in an OTC security, the Commission consider, among other matters, the public trading activity in such security, the character of such trading, the impact of such extension on the existing markets for such security, and the desirability of removing impediments to and the progress that has been made toward the development of a national market system.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 93–497 Filed 1–8–93; 8:45 am]

BILLING CODE 8010–01–M

Self-Regulatory Organizations; Midwest Stock Exchange, Inc.; Application for Unlisted Trading Privileges in Seven Over-the-Counter Issues and to Withdraw Unlisted Trading Privileges in Seven Over-the-Counter Issues

January 4, 1993.

On December 22, 1992, the Midwest Stock Exchange, Inc. ("MSE") submitted an application for unlisted trading privileges ("UTP") pursuant to section 12(f)(1)(C) of the Securities Exchange Act of 1934 ("Act") in the following over-the-counter ("OTC") securities, *i.e.*, securities not registered under section 12(b) of the Act.

File No.	Symbol	Issuer
7–9870	APBI	Applied Bioscience, International, Inc., Common Stock, $.01 par value.
7–9871	BSTN	Boston Tecnology, Inc., Common Stock, $.001 par value.
7–9872	LGNT	Legent Corp., Common Stock, $.01 par value.
7–9873	CGNE	Calgene, Inc., Common Stock, $.001 par value.
7–9874	CLCDF	Clearly Canadian Beverage Corp., Common Stock, No par value.
7–9875	TKOS	Tokos Medical Corp. (Delaware), Common Stock, $.001 par value.
7–9876	TOPP	Toppe Co., Inc. (THE), Common Stock, $.01 par value.

The above-referenced issues are being applied for as replacements for the following securities, which form a portion of the Exchange's program in which OTC securities are being traded pursuant to the granting of UTP.

The MSE also applied to withdraw UTP pursuant to section 12(f)(4) of the Act for the following issues:

File No.	Symbol	Issuer
7–9877	BELL	Bell Bancorp, Inc., Common Stock, $.01 par value.
7–9878	CDIC	Cardinal Distribution, Inc., Common Stock, No par value.
7–9879	DBRL	Dibrell Brothers, Inc., Common Stock, $1.00 par value.
7–9880	IRIC	Information Resources, Inc., Common Stock, $.01 par value.
7–9881	MAFB	MAF Bancorp, Inc., Common Stock, $.01 par value.

File No.	Symbol	Issuer
7–9882	NSBI	N.S. Bancorp, Inc., Common Stock, $.01 par value.
7–9883	SPBC	St. Paul Bancorp, Inc., Common Stock, $.01 par value.

Replacement issues are being requested due to a lack of trading activity in these issues.

Comments

Interested perrsons are invited to submit, on or before January 25, 1993, written comments, data, view and arguments concerning this application. Persons desiring to make written comments should file three copies with the Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549.

Commentators are asked to address whether they believe the requested grant of UTP as well as the withdrawal of UTP would be consistent with section 12(f)(2), which requires that, in considering an application for extension or withdrawal of UTP in an OTC security, the Commission consider, among other matters, the public trading activity in such security, the character of such trading, the impact of such extension on the existing markets for such security, and the desirability of removing impediments to and the progress that has been made toward the development of a national market system.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 93–498 Filed 1–8–93; 8:45 am]

BILLING CODE 8010-01-M

DEPARTMENT OF STATE

[Public Notice 1751]

Advisory Committee on International Communications and Information Policy; Subcommittee on Industrialized Country Policy; Meeting

The Department of State announces that the Subcommittee on Industrialized Country Policy of the Committee on International Communications and Information Policy will hold an open meeting on Tuesday, January 26, 1993, from 10 a.m.–12 noon in Room 6909, Department of State, 2201 "C" Street, NW., Washington, DC 20520.

At the meeting, there will be a report from the U.S. Delegation to the Committee for Information, Computer and Communications Policy (ICCP) of the Organization for Economic Cooperation and Development (OECD) on issues currently before the ICCP and its various working parties and experts groups. Also, ideas will be solicited to propose to the OECD for inclusion in the ICCP's 1994 work program to be determined at its next meeting in March, 1993.

Ms. Cathy Slesinger and Mr. Kenneth Leeson, co-chairs of the Subcommittee, will chair the meeting. Mr. Richard C. Beaird, Deputy U.S. Coordinator and Deputy Director, Bureau of International Communications and Information Policy, U.S. Department of State, and Chairman of the ICCP, will participate in the meeting.

Members of the general public may attend the meeting and join in the discussion, subject to the instructions of the co-chairs. Admittance of public members will be limited to seating available. In that regard, entrance to the Department of State building is controlled and individual passes are required for each attendee. Entry will be facilitated if arrangements are made in advance of the meeting.

Prior to the meeting, persons who plan to attend should so advise the office of Mr. Timothy C. Finton, Department of State, Washington, DC.; telephone (202) 647–5220. They must provide Mr. Finton with their name, title, company name, social security number, and date of birth. All attendees must use the "C" Street entrance to the building.

Dated: December 24, 1992.

Timothy C. Finton,

Chairman, U.S. Delegation to the ICCP.

[FR Doc. 93–446 Filed 1–8–93; 8:45 am]

BILLING CODE 4710-45-M

THRIFT DEPOSITOR PROTECTION OVERSIGHT BOARD

Region 1 Advisory Board

AGENCY: Thrift Depositor Protection Oversight Board.

ACTION: Change of meeting date and location.

SUMMARY: This is to announce a change in date and location for the Region 1 Advisory Board meeting scheduled for January 21 as published in the **Federal Register**, December 24, 1992, page 61468. The new meeting date is January 19 at the Sheraton River House in Miami.

DATES: January 19, 9 a.m. to 12:30 p.m.

ADDRESSES: Sheraton River House, Miami International Airport, 3900 Northwest 21st Street, Miami, Florida.

FOR FURTHER INFORMATION CONTACT: Jill Nevius, Committee Management Officer, Thrift Depositor Protection Oversight Board, 1777 F Street, NW., Washington, DC 20232, 202/786–9675.

Dated: December 5, 1993.

Jill Nevius,

Committee Management Officer.

[FR Doc. 93–445 Filed 1–8–93; 8:45 am]

BILLING CODE 2222-01-M

DEPARTMENT OF THE TREASURY

Office of the Secretary

[Department Circular—Public Debt Series—No. 2–93]

Treasury Notes of January 15, 2000, Series E–2000 (CUSIP No. 912827 J3 7)

Washington, January 6, 1993.

1. Invitation for Tenders

1.1 The Secretary of the Treasury, under the authority of chapter 31 of title 31, United States Code, invites tenders for United States securities, as described above and in the offering announcement, hereafter referred to as Notes. The Notes will be sold at auction, and bidding will be on a yield basis. Payment will be required at the price equivalent of the yield of each accepted bid. The interest rate on the Notes and the price equivalent of each accepted bid will be determined in the manner described below. Additional amounts of the Notes may be issued to Federal Reserve Banks for their own account in exchange for maturing Treasury securities. Additional amounts of the Notes may also be issued at the average price to Federal Reserve Banks, as agents for foreign and international monetary authorities.

2. Description of Securities

2.1. The issue date and maturity date of the Notes are stated in the offering announcement. The Notes will accrue interest from the issue date. Interest will be payable on a semiannual basis as described in the offering announcement through the date that the principal becomes payable. The Notes will not be subject to call for redemption prior to maturity. In the event any payment date is a Saturday, Sunday, or other nonbusiness day, the amount due will be payable (without additional interest) on the next business day.

2.2. The Notes will be issued only in book-entry form in the minimum and multiple amounts stated in the offering announcement. They will not be issued in registered definitive or in bearer form.

2.3. The Department of the Treasury's general regulations governing United States securities, i.e., Department of the Treasury Circular No. 300, current revision (31 CFR part 306), as to the extent applicable to marketable securities issued in book-entry form, and the regulations governing book-entry Treasury Bonds, Notes, and Bills, as adopted and published as a final rule to govern securities held in the TREASURY DIRECT Book-Entry Securities System in Department of the Treasury Circular, Public Debt Series, No. 2–86 (31 CFR part 357), apply to the Notes offered in this circular.

3. Sales Procedures

3.1. Tenders will be received at Federal Reserve Banks and Branches and at the Bureau of the Public Debt, Washington, DC 20239–1500. The closing times for the receipt of noncompetitive and competitive tenders are specified in the offering announcement. Noncompetitive tenders will be considered timely if postmarked (U.S. Postal Service cancellation date) no later than the day prior to the auction and received no later than close of business on the issue day.

3.2. The par amount of Notes bid for must be stated on each tender. The minimum bid is stated in the offering announcement, and larger bids must be in multiples of that amount.

3.3. Competitive bids must also show the yield desired, expressed in terms of an annual yield with two decimals, e.g., 7.10%. Fractions may not be used. A single bidder, as defined in Treasury's single bidder guidelines contained in Attachment A to this circular, may submit bids at more than one yield. However, at any one yield, the Treasury will not recognize any amount tendered by a single bidder in excess of 35 percent of the public offering amount. A competitive bid by a single bidder at any one yield in excess of 35 percent of the public offering will be reduced to that amount.

3.4. Noncompetitive tenders do not specify a yield. A single bidder should not submit a noncompetitive tender for more than $5,000,000. A noncompetitive bid by a single bidder in excess of $5,000,000 will be reduced to that amount. A bidder, whether bidding directly or through a depository institution or a government securities broker/dealer, may not submit a noncompetitive bid for its own account in the same auction in which it is submitting a competitive bid for its own account. A bidder may not submit a noncompetitive bid if the bidder holds a position, in the Notes being auctioned, in "when-issued" trading, or in futures or forward contracts. A noncompetitive bidder may not enter into any agreement to purchase or sell or otherwise dispose of the security being auctioned, nor may it commit to sell the security prior to the designated closing time for receipt of competitive bids.

3.5. The following institutions may submit tenders for accounts of customers: depository institutions, as described in section 19(b)(1)(A), excluding those institutions described in subparagraph (vii), of the Federal Reserve Act (12 U.S.C. 461(b)(1)(A)); and government securities broker/dealers that are registered with the Securities and Exchange Commission or noticed as government securities broker/dealers pursuant to Section 15C(a)(1) of the Securities Exchange Act of 1934. Others are permitted to submit tenders only for their own account. A submitted, if bidding competitively for customers, must include a customer list with the tender giving, for each customer, the name of the customer and the amount bid. A separate tender and customer list should be submitted for each competitive yield. For noncompetitive bids, the customer list must provide, for each customer, the name of the customer and the amount bid. For mailed tenders, the customer list must be submitted with the tender. For other than mailed tenders, the customer list should accompany the tender. If the customer list is not submitted with the tender, information for the list must be complete and available for review by the deadline for submission of noncompetitive tenders. The customer list should be received by the Federal Reserve Bank on auction day. All competitive and noncompetitive bids submitted on behalf of trust estates must provide, for each trust estate, the name or title of the trustee(s), a reference to the document creating the trust with the date of execution, and the employer identification number of the trust. Customer bids may not be aggregated on the customer list. The customer list must include customers and customers of those customers, where applicable.

3.6. A competitive single bidder must report its net long position if the total of all its bids for the security being offered and its net position in the security equals or exceeds $2 billion, with the position to be determined as of one half-hour prior to the closing time for the receipt of competitive tenders. A net long position includes positions, in the security being auctioned, in "when-issued" trading, and in futures and forward contracts. Bidders who meet this reporting requirement and are customers of a depository institution or a government securities broker/dealer must report their positions through the institution submitting the bid on their behalf.

3.7. Tenders from bidders who are making payment by charge to a funds account at a Federal Reserve Bank and tenders from bidders who have an approved autocharge agreement on file at a Federal Reserve Bank will be received without deposit. In addition, tenders from States, and their political subdivisions or instrumentalities; public pension and retirement and other public funds; international organizations in which the United States holds membership; foreign central banks and foreign states; and Federal Reserve Banks will be received without deposit. Tenders from all others, including tenders submitted for Notes to be maintained on the book-entry records of the Department of the Treasury, must be accompanied by full payment for the amount of Notes applied for, or by a guarantee from a commercial bank or a primary dealer of 5 percent of the par amount applied for.

3.8. After the deadline for receipt of competitive tenders, there will be a public announcement of the amount and yield range of accepted bids. Subject to the reservations expressed in section 4, noncompetitive bids will be accepted in full, and then competitive bids will be accepted, starting with those at the lowest yields, through successively higher yields to the extent required to attain the amount offered. Bids at the highest accepted yield will be prorated if necessary. After the determination is made as to which bids are accepted, an interest rate will be established, at a ⅛ of one percent increment, which results in an equivalent average accepted price close to 100.000 and a lowest accepted price above the original issue discount limit. That stated rate of interest will be paid on all of the Notes. Based on such interest rate, the price on each competitive tender allotted will be determined and each successful competitive bidder will be required to pay the price equivalent to the yield bid. Those submitting noncompetitive bids will pay the price equivalent to the weighted average yield of accepted competitive bids. Price calculations will be carried to three decimal places on the basis of price per hundred, e.g., 99.923, and the determinations of the Secretary of the Treasury shall be final. If the amount of noncompetitive bids received would absorb all or most of the offering, competitive bids will be accepted in an amount sufficient to provide a fair determination of the yield. Bids received from Federal Reserve Banks

will be accepted at the price equivalent to the weighted average yield of accepted competitive bids.

3.9. No single bidder will be awarded securities in an amount exceeding 35 percent of the public offering. The determination of the maximum award to a single bidder will take into account the bidder's net long position, if the bidder has been obliged to report its position per the requirements outlined in section 3.6.

3.10. Notice of awards will be provided by a Federal Reserve Bank or Branch or the Bureau of the Public Debt to bidders who have submitted accepted competitive bids, whether for their own account or for the account of customers. Those submitting non-competitive bids will be notified only if the bid is not accepted in full, or when the price at the average yield is over par. No later than 12:00 noon local time on the day following the auction, the appropriate Federal Reserve Bank will notify each depository institution that has entered into an autocharge agreement with a bidder as to the amount to be charged to the institution's funds account at the Federal Reserve Bank on the issue date. Any customer that is awarded $500 million or more of securities must furnish, no later than 10 a.m. local time on the day following the auction, written confirmation of its bid to the Federal Reserve Bank or Branch where the bid was submitted. A depository institution or government securities broker/dealer submitting a bid for a customer is responsible for notifying its customer of this requirement if the customer is awarded $500 million or more of securities as a result of bids submitted by the depository institution or government securities broker/dealer.

4. Reservations

4.1. The Secretary of the Treasury expressly reserves the right to accept or reject any or all bids in whole or in part, to allot more or less than the amount of Notes specified in the offering announcement, and to make different percentage allotments to various classes of applicants when the Secretary considers it in the public interest. The Secretary's action under this section is final.

5. Payment and Delivery

5.1. Settlement for the Notes allotted must be made timely at the Federal Reserve Bank or Branch or at the Bureau of the Public Debt, wherever the tender was submitted. Settlement on Notes allotted will be made by a charge to a funds account or pursuant to an approved autocharge agreement, as provided in section 3.7. Settlement on Notes allotted to institutional investors and to others whose tenders are accompanied by a guarantee as provided in section 3.7. must be made or completed on or before the issue date. Payment in full must accompany tenders submitted by all other investors. Payment must be in cash; in other funds immediately available to the Treasury; in Treasury notes or bonds maturing on or before the settlement date but which are not overdue as defined in the general regulations governing United States securities; or by check drawn to the order of the institution to which the tender was submitted, which must be received from institutional investors by the time stated in the offering announcement. When payment has been submitted with the tender and the purchase price of the Notes allotted is over par, settlement for the premium must be completed timely, as specified above. When payment has been submitted with the tender and the purchase price is under par, the discount will be remitted to the bidder.

5.2. In every case where full payment has not been completed on time, an amount of up to 5 percent of the par amount of Notes allotted may, at the discretion of the Secretary of the Treasury, be forfeited to the United States.

5.3. Registered definitive securities tendered in payment for the Notes allotted and to be held in TREASURY DIRECT are not required to be assigned if the inscription on the registered definitive security is identical to the registration of the Note being purchased. In any such case, the tender form used to place the Notes allotted in TREASURY DIRECT must be completed to show all the information required thereon, or the TREASURY DIRECT account number previously obtained.

6. General Provisions

6.1. As fiscal agents of the United States, Federal Reserve Banks are authorized, as directed by the Secretary of the Treasury, to receive tenders, to make allotments, to issue such notices as may be necessary, to receive payment for, and to issue, maintain, service, and make payment on the Notes.

6.2. The Secretary of the Treasury may at any time supplement or amend provisions of this circular if such supplements or amendments do not adversely affect existing rights of holders of the Notes. Public announcement of such changes will be promptly provided.

6.3. The Notes issued under this circular shall be obligations of the United States, and, therefore, the faith of the United States Government is pledged to pay, in legal tender, principal and interest on the Notes.

6.4. Attachment A and the offering announcement are incorporated as part of this circular.

Gerald Murphy,

Fiscal Assistant Secretary.

Attachment A—Treasury's Single Bidder Guidelines for Noncompetitive Bidding in All Treasury Security Auctions

The investor categories listed below define what constitutes a single noncompetitive bidder.

(1) *Bank Holding Companies and Subsidiaries*—

A bank holding company (includes the company and/or one or more of its subsidiaries, whether or not organized as separate entities under applicable law).

(2) *Banks and Branches*—

A parent bank (includes the parent and/or one or more of its branches, whether or not organized as separate entities under applicable law).

(3) *Thrift Institutions and Branches*—

A thrift institution, such as a savings and loan association, credit union, savings banks, or other similar entity (includes the principal or parent office and/or one or more of its branches, whether or not organized as separate entities under applicable law).

(4) *Corporations and Subsidiaries*—

A corporation (includes the corporation and/or one or more of its majority-owned subsidiaries, i.e., any subsidiary more than 50 percent of whose stock is owned by the parent corporation or by any other of its majority-owned subsidiaries).

(5) *Familes*—

A married person (includes his or her spouse, and any unmarried adult children, having a common address and/or household).

Note: A minor child, as defined by the law of domicile, is not permitted to submit tenders individually, or jointly with an adult bidder. (A minor's parent acting as natural guardian is not recognized as a separate bidder.)

(6) *Partnerships*—

Each partnership (includes a partnership or individual partner(s), acting together or separately, who own the majority or controlling interest in other partnerships, corporations, or associations).

(7) *Guardians, Custodians, or other Fiduciaries*—

A guardian, custodian, or similar fiduciary, identified by (a) the name or title of the fiduciary, (b) reference to the document, court order, or other authority under which the fiduciary is acting, and (c) the taxpayer identifying number assigned to the estate.

(8) *Trusts*—

A trust estate, which is identified by (a) the name or title of the trustee, (b) a reference to the document creating the trust, e.g., a trust indenture, with date of execution, or a will, (c) the IRS employer identification number (not social security account number).

(9) *Political Subdivisions*—

(a) A state government (any of the 50 states and the District of Columbia).

(b) A unit of local government (any county, city, municipality, or township, or other unit

of general government, as defined by the Bureau of the Census for statistical purposes, and includes any trust, investment, or other funds thereof).

(c) A commonwealth, territory, or possession.

(10) *Mutual Funds*—

A mutual fund (includes all funds that comprise it, whether or not separately administered).

(11) *Money Market Funds*—

A money market fund (includes all funds that have a common management).

(12) *Investment Agents/Money Managers*—

An individual, firm, or association that undertakes to service, invest, and/or manage funds for others.

(13) *Pension Funds*—

A pension fund (includes all funds that comprise it, whether or not separately administered).

Notes: The definitions do not reflect all bidder situations. "Single bidder" is not necessarily synonymous with "single entity".

Questions concerning the guidelines should be directed to the Office of Financing, Bureau of the Public Debt, Washington, DC 20239 (telephone 202/219–3350).

Auction of 7-Year Notes Totaling $9,750 Million

The Treasury will auction $9,750 million of 7-year notes to refund $6,195 million of 7-year notes maturing January 15, 1993, and to raise about $3,550 million new cash. The $6.195 million of maturing 7-year notes are those held by the public, including $528 million currently held by Federal Reserve Banks as agents for foreign and international monetary authorities.

The $9,750 million is being offered to the public, and any amounts tendered by Federal Reserve Banks as agents for foreign and international monetary authorities will be added to that amount. Tenders for such accounts will be accepted at the average price of accepted competitive tenders.

In addition to the public holdings, Federal Reserve Banks for their own accounts hold $320 million of the maturing securities that may be refunded by issuing additional amounts of the new notes at the average price of accepted competitive tenders.

Details about the new security are given in the attached highlights of the offering and in the official offering circular.

Attachment

Highlights of Treasury Offering to the Public of 7-Year Notes To Be Issued January 15, 1993

January 6, 1993

Amount Offered:	
To the public	$9,750 million
Description of Security:	
Term and type of security.	7-year notes.
Series and CUSIP designation	E–2000 (CUSIP No. 912827 J3 7).
Maturity date	January 15, 2000.
Interest rate	To be determined based on the average of accepted bids.
Investment yield	To be determined at auction.
Premium or discount.	To be determined after auction.
Interest payment dates.	July 15 and January 15.
Minimum denomination available.	$1,000.
Terms of Sale:	
Method of sale	Yield auction.
Competitive tenders.	Must be expressed as an annual yield, with two decimals, e.g., 7.10%.
Noncompetitive tenders.	Accepted in full at the average price up to $5,000,000.
Accrued interest payable by investor.	None.
Key Dates:	
Receipt of tenders.	Wednesday, January 13, 1993.
(a) noncompetitive.	Prior to 12:00 noon, EST.
(b) competitive	Prior to 1:00 p.m., EST.
Settlement (final payment due from institutions):	
(a) funds immediately available to the Treasury.	Friday, January 15, 1993.
(b) readily-collectible check.	Wednesday, January 13, 1993.

[FR Doc. 93–578 Filed 1–7–93; 8:45 am]

BILLING CODE 4810–40–M

Public Information Collection Requirements Submitted to OMB for Review

Date: January 5, 1993.

The Department of Treasury has submitted the following public information collection requirement(s) to OMB for review and clearance under the Paperwork Reduction Act of 1980, Public Law 96–511. Copies of the submission(s) may be obtained by calling the Treasury Bureau Clearance Officer listed. Comments regarding this information collection should be addressed to the OMB reviewer listed and to the Treasury Department Clearance Officer, Department of the Treasury, room 3171 Treasury Annex, 1500 Pennsylvania Avenue, NW., Washington, DC 20220.

Financial Management Service

OMB Number: New
Form Number: None
Type of Review: New collection
Title: Green Book Survey
Description: The data collected will be used to determine the effectiveness of the Green Book and identify areas which need improvement.
Respondents: Businesses or other for-profit, Small businesses or organizations
Estimated Number of Respondents: 9,000
Estimated Burden Hours Per Response: 15 minutes
Frequency of Response: Other (One-time survey)
Estimated Total Reporting Burden: 2,250 hours
Clearance Officer: Jacqueline R. Perry (301) 344–8577, Financial Management Service, 3361–L 75th Avenue, Landover, MD 20785
OMB Reviewer: Milo Sunderhauf (202) 395–6880, Office of Management and Budget, room 3001, New Executive Office Building, Washington, DC 20503

Lois K. Holland,

Departmental Reports Management Officer.

[FR Doc. 93–529 Filed 1–8–93; 8:45 am]

BILLING CODE 4810–35–M

Public Information Collection Requirements Submitted to OMB for Review

Date: January 5, 1993.

The Department of Treasury has submitted the following public information collection requirement(s) to OMB for review and clearance under the Paperwork Reduction Act of 1980, Public Law 96–511. Copies of the submission(s) may be obtained by calling the Treasury Bureau Clearance Officer listed. Comments regarding this information collection should be addressed to the OMB reviewer listed and to the Treasury Department Clearance Officer, Department of the Treasury, Room 3171, Treasury Annex, 1500 Pennsylvania, NW., Washington, DC 20220.

Department Offices

OMB Number: 1505–0118
Form Number: TD F 90–22.39
Type of Review: Extension
Title: Travel to Cuba, U.S. Department of the Treasury, Office of Foreign Assets Control, Declaration
Description: Declarations to be completed by persons traveling from the U.S. to Cuba will provide the U.S. Government information to be used in administering and enforcing economic sanctions imposed against Cuba pursuant to 31 CFR part 515
Respondents: Individual or households, Businesses or other for-profit, Federal agencies or employees, Non-profit institutions, Small business or organizations
Estimated Number of Respondents: 26,000

Estimated Burden Hours Per Response: 5 minutes
Frequency of Response: On occasion
Estimated Total Reporting Burden: 2,166 hours
Clearance Officer: Lois K. Holland (202) 622–1563, Departmental Offices, Room 3171, Treasury Annex, 1500 Pennsylvania Avenue, NW., Washington, DC 20220
OMB Reviewer: Milo Sunderhauf (202) 395–6880, Office of Management and Budget, Room 3001, New Executive Office Building, Washington, DC 20503

Lois K. Holland,

Departmental Reports Management Officer.

[FR Doc. 93–530 Filed 1–8–93; 8:45 am]

BILLING CODE 4810-25-M

Customs Service

[T.D. 93–4]

Revocation of Individual Broker License No. 4063; Kenneth A. Anderson, Jr.

AGENCY: U.S. Customs Service, Department of the Treasury.

ACTION: General notice.

SUMMARY: Notice is hereby given that the Secretary of the Treasury, pursuant to section 641, Tariff Act of 1930, as amended (19 U.S.C. 1641), and part 111.74 of the Customs Regulations, as amended (19 CFR 111.74), revoked the individual broker license no. 4063 issued to Kenneth A. Anderson, Jr. This action having been upheld by the United States Court of International Trade (Court No. 90–11–00617); and, under appeal, by the Court of Appeals for the Federal Circuit (Appeal No. 92–1444) is effective as of November 28, 1992.

Dated: January 5, 1993.

Thomas P. Banner,

Acting Deputy Director, Office of Trade Operations.

[FR Doc. 93–469 Filed 1–8–93; 8:45 am]

BILLING CODE 4820-02-M

Office of Thrift Supervision

[AC–1: OTS No. 3404]

First Federal Savings Bank of Maryville, Maryville, TN; Approval of Conversion Application

Notice is hereby given that on December 28, 1992, the Deputy Assistant Director, Corporate Activities Division, Office of Thrift Supervision, or her designee, acting pursuant to delegated authority, approved the application of First Federal Savings Bank of Maryville, Maryville, Tennessee for permission to convert to the stock form of organization. Copies of the application are available for inspection at the Information Services Division, Office of Thrift Supervision, 1776 G Street, NW., Washington, DC 20552, and the Central Regional Office, Office of Thrift Supervision, 111 East Wacker Drive, Suite 800, Chicago, Illinois 60601.

Dated: January 6, 1993.

By the Office of Thrift Supervision.

Nadine Y. Washington,

Corporate Secretary.

[FR Doc. 92–552 Filed 1–8–92; 8:45 am]

BILLING CODE 6720-01-M

Sunshine Act Meetings

Federal Register
Vol. 58, No. 6
Monday, January 11, 1993

This section of the FEDERAL REGISTER contains notices of meetings published under the "Government in the Sunshine Act" (Pub. L. 94-409) 5 U.S.C. 552b(e)(3).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice

(January 6, 1993)

The following notice of meeting is published pursuant to Section 3(a) of the Government in the Sunshine Act (Pub. L. No. 94–409), 5 U.S.C. 552b:

DATE AND TIME: January 13, 1993, 10 a.m.

PLACE: 825 North Capitol Street NE., Room 9306, Washington, DC 20426.

STATUS: Open.

MATTERS TO BE CONSIDERED: Agenda.

*Note.—Items listed on the agenda may be deleted without further notice.

CONTACT PERSON FOR MORE INFORMATION: Lois D. Cashell, Secretary, Telephone (202) 208–0400. For a recording listing items stricken from or added to the meeting, call (202) 208–1627.

This is a list of matters to be considered by the Commission. It does not include a listing of all papers relevant to the items on the agenda; however, all public documents may be examined in the Reference and Information Center.

Consent Agenda—Hydro, 971st Meeting—January 13, 1993, Regular Meeting (10:00 a.m.)

CAH–1.
Project No. 8835–017, Dewey B. Smith
CAH–2.
Project No. 2614–018, City of Hamilton, Ohio
CAH–3.
Project Nos. 1953–006 and 008, Consolidated Water Power Company
CAH–4.
Project No. 1957–004, Wisconsin Public Service Corporation
CAH–5.
Project No. 11080–001, Eagle Mountain Energy Company
CAH–6.
Omitted
CAH–7.
Project No. 1417–042, Central Nebraska Public Power and Irrigation District
Project No. 1835–080, Nebraska Public Power District
CAH–8.
Project No. 7270–012, Northern Wasco County People's Utility District
CAH–9.
Project Nos. 2110–002, 2192–005, 2256–002 and 2590–002, Consolidated Water Power Company
CAH–10.
Project No. 2523–002, Wisconsin Electric Power Company
CAH–11.
Project Nos. 9885–027, 032 and 033, Marysville Hydro Partners

Consent Electric Agenda

CAE–1.
Docket No. ER92–533–000, Louisville Gas and Electric Company
CAE–2.
Docket No. EL92–24–001, The Algoma Group v. Wisconsin Public Service Corporation
CAE–3.
Docket No. RM92–3–000, Annual Update of Commission Filing Fees
CAE–4.
Docket No. EL92–22–000, City of Lebanon, Ohio v. Cincinnati Gas & Electric Company
CAE–5.
Docket No. EL92–42–000, UNITIL Power Corporation v. Public Service Company of New Hampshire and Northeast Utilities
CAE–6.
Omitted
CAE–7.
Docket No. EL91–36–000, Northeast Utilities Service Company
CAE–8.
Docket No. ER92–809–001, Illinois Power Company
CAE–9.
Docket No. EC88–2–009, Utah Power & Light Company, PacifiCorp, and PC/UP&L Merging Corporation

Consent Miscellaneous

CAM–1.
Docket No. RM93–6–000, Repeal of Certain Standards of Conduct Provisions in Part 3c
CAM–2.
(A) Docket No. RO86–13–000, Merit Petroleum, Inc.
(B) Docket No. RO87–6–000, Petrade International, Inc.
(C) Docket No. RO88–11–000, Port Petroleum, Inc., Morris M. James, T. Michael Howell, and C. Geogory Crafts
(D) Docket No. RO88–1–000, Leonard O. Rice d/b/a Rice Oil Company and Rice-Lindquist, Inc.

Consent Oil and Gas Agenda

CAG–1.
Omitted
CAG–2.
Docket Nos. TM93–2–24–000, 001 and 002, Equitrans, Inc.
CAG–3.
Docket Nos. RP93–31–000 and CP88–328–000, Transcontinental Gas Pipe Line Corporation
CAG–4.
Omitted
CAG–5.
Docket No. TA92–1–28–008, Panhandle Eastern Pipe Line Company
CAG–6.
Docket Nos. RP92–215–000 and 001, Columbia Gas Transmission Corporation
CAG–7.
Docket Nos. RP88–228–039, 040, CP87–115–008, 009, RP88–249–009, 010, RP86–119–027, 030, RP92–206–001, RP88–191–030, RP89–30–006, RP90–122–009, RP91–167–008, RP89–29–013, RP89–149–009, RP89–242–008, CP89–470–006, TA84–2–9–022, TA85–1–9–014, TA89–1–9–004, TA90–1–9–008, TA91–1–9–006, RP91–16–004, 005, CP87–103–011, CP91–3135–005, RP91–210–013 and RP92–220–003, Tennessee Gas Pipeline Company
CAG–8.
Docket No. RP92–132–008, Tennessee Gas Pipeline Company
CAG–9.
Docket No. RP92–132–009, Tennessee Gas Pipeline Company
CAG–10.
Docket No. RP92–165–007, Trunkline Gas Company
CAG–11.
Docket Nos. RP93–4–001 and RS92–43–001, Mississippi River Transmission Corporation
CAG–12.
Docket No. RP89–185–007, Panhandle Eastern Pipe Line Company
CAG–13.
Docket Nos. RP87–30–000 (Phase II) and RP90–69–000 (Phase A), Colorado Interstate Gas Company
CAG–14.
Docket No. RP91–143–000, Great Lakes Gas Transmission Limited Partnership
CAG–15.
Docket No. RM87–17–004, Natural Gas Data Collection System
CAG–16.
Omitted
CAG–17.
Docket No. GP91–8–001, Jack J. Grynberg, Individually and as General Partner for the Greater Green River Basin Drilling Program: 72–73 v. Rocky Mountain Natural Gas Company, a division of KN Energy, Inc.
Docket No. GP91–10–001, Rocky Mountain Natural Gas Company v. Jack J. Grynberg, Individually and as General Partner for the Greater Green River Basin Drilling Program: 72–73
CAG–18.
Docket No. GP89–54–000, Amoco Production Company
CAG–19.

Docket No. RS92–87–002, Transwestern Pipeline Company

CAG–20.
Docket Nos. RP93–5–002 and RS92–69–001, Northwest Pipeline Corporation

CAG–21.
Docket Nos. RS92–60–005 and RP92–214–003, El Paso Natural Gas Company

CAG–22.
Docket Nos. CP93–57–000, RS92–82–000 and CP92–189–001, Superior Offshore Pipeline Company
Docket No. CP93–47–000, United Gas Pipe Line Company
Docket No. CP76–304–000, Transcontinental Gas Pipe Line Corporation

CAG–23.
Docket No. CP92–504–001, Arkla Energy Resources, a Division of Arkla, Inc. and Arkla Energy Resources Company

CAG–24.
Docket No. CP92–498–001, Trunkline Gas Company

CAG–25.
Docket No. CP90–2155–001, Southern Natural Gas Company

CAG–26.
Docket No. CP90–1249–001, Colorado Interstate Gas Company

CAG–27.
Docket No. CP92–441–001, National Fuel Gas Supply Corporation and Tennessee Gas Pipeline Company

CAG–28.
Omitted

CAG–29.
Docket No. CP92–472–001, Equitrans, Inc.

CAG–30.
Omitted

CAG–31.
(A) Docket Nos. CP89–800–000 and 001, Panhandle Eastern Pipe Line Company
(B) Docket No. CP92–190–000, Panhandle Eastern Pipe Line Company
Docket No. CP92–203–000, KN Wattenburgh Transmission Limited Liability Company
Docket No. CP92–208–000, KN Front Range Gathering Company

CAG–32.
Omitted

CAG–33.
Omitted

CAG–34.
Docket No. CP92–351–000, Williams Natural Gas Company
Docket No. CP92–416–000, Trident NGL, Inc. and Oryx Energy Company

CAG–35.
Docket No. CP89–2165–002, Algonquin Gas Transmission Company

CAG–36.
Docket No. RM90–7–003, Revisions to Regulations Governing Transportation under Section 311 of the Natural Gas Policy Act of 1978 and Blanket Transportation Certificates
Docket Nos. CP93–11–000 and CP93–83–000, El Paso Natural Gas Company

CAG–37.
Docket Nos. CP92–44–000 and 001, El Paso Natural Gas Company

CAG–38.
Docket No. CP92–273–000, West Texas Gas, Inc.

CAG–39.
Docket No. CP92–592–000, United Gas Pipe Line Company

CAG–40.
Docket No. CP91–2904–000, Mississippi River Transmission Corporation

CAG–41.
Docket Nos. RP88–259–060, 059, CP89–1227–000, RP90–124–000, RP90–161–000, RP92–228–000 and RP92–1–008, Northern Natural Gas Company

CAG–42.
Docket Nos. RP91–187–007, CP91–2448–000 and FA91–23–001, Florida Gas Transmission Company

Hydro Agenda

H–1.
Reserved

Electric Agenda

E–1.
Docket No. ER92–280–000, Public Service Electric and Gas Company. Order on transmission rate filing.

E–2.
Docket Nos. ER92–317–001 and ER92–456–001, Public Service Company of Colorado. Order on rehearing regarding transmission rate filing.

E–3.
Docket Nos. EC92–21–000 and ER92–806–000, Entergy Services, Inc. and Gulf States Utilities Company. Order on rate filing and request for merger authorization.

E–4.
Omitted

Miscellaneous Agenda

M–1.
Reserved

Oil and Gas Agenda

I. Pipeline Rate Matters

PR–1.
(A) Docket No. RP91–143–005, Great Lakes Gas Transmission Limited Partnership. Order on rehearing.
(B) Docket Nos. RP89–186–008 and RP90–20–005, Great Lakes Gas Transmission Limited Partnership. Order on rehearing.

II. Restructuring Matters

RS–1.
Docket No. RS92–11–000, Texas Eastern Transmission Corporation. Order on Order No. 636 compliance filing.

III. Pipeline Certificate Matters

PC–1.
Docket Nos. CP92–184–000 and 001, Texas Eastern Transmission Corporation
Docket Nos. CP92–185–000 and 001, Algonquin Gas Transmission Company. Application to construct facilities and to provide firm transportation for six shippers.

PC–2.
Docket Nos. CP91–732–003 and CP88–332–024, Indicated Shippers v. El Paso Natural Gas Company. Order on rehearing.

PC–3.
Docket No. CP80–34–009, Panhandle Eastern Pipe Line Company
Docket No. CP80–35–009, Colorado Interstate Gas Company. Application to amend existing exchange/transportation/sales agreement.

PC–4.
Docket Nos. CP92–182–000, 001 and 002, Florida Gas Transmission Company
Docket No. CP92–415–000, Transcontinental Gas Pipe Line Corporation and Florida Gas Transmission Company. Application to construct Phase III facilities and application for expansion of Mobile Bay facilities.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–677 Filed 1–7–93; 2:50 pm]

BILLING CODE 6717–01–M

federal register

Monday
January 11, 1993

Part II

Environmental Protection Agency

40 CFR Part 72, et al.
Acid Rain Program; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 72, 73, 75, 77 and 78
[FRL–4543–5]

Acid Rain Program: General Provisions and Permits, Allowance System, Continuous Emissions Monitoring, Excess Emissions and Administrative Appeals

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Title IV of the Clean Air Act (the Act), as amended November 15, 1990, requires the Environmental Protection Agency (EPA or Agency) to establish an Acid Rain Program to reduce the adverse effects of acidic deposition. To implement this statutory mandate, the Acid Rain Program requirements will be codified in seven regulations. This action delineates all or portions of five final regulations that were initially proposed December 3, 1991: General Provisions and Permits; the Allowance System; Continuous Emissions Monitoring; Excess Emissions Penalties; and Administrative Appeals. (The administrative appeals procedures were originally proposed as a subpart of the permits rule; EPA has decided to remove it from part 72 and place it in a separate part 78.)

In addition to the final rules, this action includes a brief overview of the acid rain problem, summaries of major provisions of the proposed rules, the public's comments on these proposals, and summaries of the major changes that have been made in this final rule.

DATES: These rules become effective February 10, 1993. The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of February 10, 1993.

FOR FURTHER INFORMATION CONTACT: Brian McLean, Director, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460. (617) 674–7377.

SUPPLEMENTARY INFORMATION:

I. General Background

The burning of fossil fuels, particularly coal and oil, releases emissions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) into the atmosphere. Once in the air, SO_2 and NO_x may undergo various chemical reactions, resulting in transformation of the emissions into sulfates, nitrates, sulfuric acid and nitric acid. These compounds can fall to earth near the emission sources of SO_2 and NO_x or be transported hundreds of miles. Referred to as acidic deposition or acid rain, these compounds can be either dry (gases, aerosols, and particles) or wet (precipitation such as rain, fog, or snow). SO_2, and NO_x emissions and their byproducts damage ecosystems and man-made materials, are suspected of posing a threat to human health at current levels, and reduce visibility.

Of the approximately 23 million tons of SO_2 and 19 million tons of NO_x emitted annually from all sources in the United States in 1985, about 16 million tons of SO_2 and 7 million tons of NO_x were emitted by electric utilities. Title IV of the Act requires EPA to establish an Acid Rain Program and a national emissions cap of 8.95 million tons per year on electric utility SO_2 emissions to be implemented in two phases. Phase I (beginning in 1995) requires the 110 highest-emitting utility plants to meet an intermediate SO_2 emissions limitation. By the year 2000 (in which Phase II begins) virtually all other utility units with output capacity greater than 25 megawatts and all new utility units will be required to meet emissions limitations as well. Total annual SO_2 emissions will be reduced by 10 million tons below 1980 levels beginning in the year 2000, a reduction of total SO_2 emissions of approximately 40%. Title IV also requires that certain coal-fired electric utility boilers reduce their emissions of NO_x through installation of low NO_x burner technologies at the same time they are required to comply with the SO_2 limitations. However, these rules do not address the NO_x reduction provisions of the Act.

The centerpiece of the Acid Rain Program is a unique trading system in which allowances (each authorizing the emission of up to one ton of SO_2) are bought and sold at prices determined in a free market. Existing utility sources are allocated allowances based on their historic fuel use and the emissions limitations specified in the Act. Utility units are required to limit SO_2 emissions to the number of allowances they hold, but since allowances are fully transferrable, utilities may meet their emissions control requirements in the most cost-effective manner possible. For instance, a utility may decide to (1) switch to a lower sulfur fuel, (2) install flue gas desulfurization equipment (scrubbers) and bank unused allowances or sell them to other utilities/individuals, (3) forego emissions reductions and buy additional allowances (if necessary) or (4) implement energy efficiency measures at the plant or by encouraging customers to undertake them. Other options and combinations of options are possible, providing an unusually high degree of flexibility for affected sources to comply with the law. The procedures for transferring and tracking allowances are codified in 40 CFR part 73.

In order to operate, each affected source must apply for a permit in which the source certifies that it will hold a sufficient number of allowances to cover its SO_2 emissions, and specifies the source's planned method of compliance. The permit regulation is codified in 40 CFR part 72.

In order to ensure that source compliance results in achieving nationally mandated reductions in SO_2 and NO_x emissions, each affected source must install a system to continuously monitor the emissions and to collect, record, and report emissions data. The continuous emissions monitoring rule is codified in 40 CFR part 75.

If an affected unit exceeds its emissions limitation for either SO_2 or NO_x, the Act requires the affected source to pay penalties and, for SO_2, to submit a plan detailing how the excess SO_2 emissions will be offset and when. These requirements act as a strong incentive for compliance with the mandated emissions reductions of the Acid Rain Program. Excess emissions penalty requirements are codified in 40 CFR part 77.

Finally, should there be disputes over decisions by the Administrator regarding any aspect of the Acid Rain Program, administrative appeals procedures are defined in 40 CFR part 78.

II. Acid Rain Rulemaking Overview

Prior to the publication of the proposed acid rain regulations, EPA solicited comments and ideas from many individuals and organizations that would be affected by such rules. The Acid Rain Advisory Committee (ARAC) was formed for that purpose, and included 44 members representing various stakeholder groups, including utilities, emissions control equipment vendors, State Public Utility Commissioners, academicians, coal companies, State air pollution control agencies, labor, and environmental groups. In addition to the Committee members, hundreds of people attended the six ARAC public meetings and participated in varying degrees in the discussions. Input from these stakeholders and others was extremely helpful in drafting the proposed acid rain rules.

To date, the Agency has proposed three rulemaking packages pursuant to title IV of the Act and finalized one. The first, proposed on May 23, 1991 and finalized December 17, 1991, was

subpart E of 40 CFR part 73 which governs the auction and sale of allowances under the Acid Rain Program. Recently, on July 7, 1992, subparts B and G of 40 CFR part 73 were proposed for public comment. These subparts address the allocation of allowances to electric utilities and small diesel refineries.

The most extensive of the acid rain proposals (hereafter referred to as the "core rules") were proposed in the Federal Register on December 3, 1991. That proposal addressed the acid rain permitting procedures for electric utilities, including administrative appeals (part 72); the operation of the allowance system, including the conservation and renewable energy reserve (subparts A, C, D, and F of part 73); installation and operation of continuous emission monitors (part 75); and penalty procedures if emissions exceed allowances held or emissions limitations (part 77). The core rules are finalized in today's rulemaking.

Between January 6 and 10, 1992, EPA conducted public hearings in Washington, DC, Chicago, and San Francisco on the core rules. Testimony was given by 33 individuals, representing industry, State regulatory organizations, and environmental groups. A full record of both written and oral comment is available in the EPA docket on this rulemaking.

During the public comment period, which closed on February 12, 1992, the Agency received 3249 letters, documents, and telephone communications from a wide variety of interested parties. The general public submitted 2576 letters; private industry, 434; local governments, 131; state agencies and governors, 42; Congress, 32; and environmental groups, 31. These communications contained over 7800 individual comments focused on over 850 major and minor issues. Approximately 80% of the comments were focused on 14 major issue areas. These issue areas are addressed in the preamble that follows, along with other issues that received fewer comments but are judged by the Agency to be of sufficient importance to discuss here. All public comments and the Agency's response to each are available at the docket established for this rule at EPA Headquarters, Air Docket, room M–1500, 1st floor, 401 M Street, SW., Washington, DC, 20460, between the hours of 8:30 a.m. and noon, and 1:30 p.m. to 3:30 p.m., Monday through Friday.

Structural Changes to Today's Rules

Although the final rules published in today's notice remain consistent in content and relatively similar in form with those proposed in December 1991, some structural changes have been made to improve the cogency and general readability of the rules. In drafting the final rules, EPA has endeavored to simplify and streamline the text wherever possible; sections have been relocated to improve the flow of information, redundancies eliminated, and many sections rewritten to enhance clarity. Major changes are noted below. More specific structural changes that are unique to each rule are addressed in the preamble section for that rule.

Definitions and Abbreviations

The proposed rules included definitions and abbreviations sections and other general provisions within the body of each part. This resulted in both redundancies and inconsistencies across rules. In response to public comment on this issue, the Agency has placed all definitions, abbreviations, State and Federal authorities, and other general provisions for parts 72–78 in subpart A of part 72.

EPA has also revised a number of term definitions to improve clarity; others whose meanings were analogous to common English usage have been deleted. Some definitions have been removed because they explain terms that were more appropriately delineated in substantive portions of the rules. Composite term definitions that incorporate expressions defined separately have been eliminated, as well as definitions of terms no longer used in the rules.

All of these steps are intended to ease the task of referencing and understanding terms for the reader and ensure that term definitions are now consistent across all rules. Changes made to individual terms based on public comment on the term itself, on issues that impact the term, or new terms and definitions suggested by the public, are discussed in the appropriate section of the preamble.

Opt-ins Provisions

The proposed core rules contained various provisions concerning opt-in sources under section 410 of the Act. Because the Agency is still developing regulations on opt-ins, virtually all provisions and references to opt-ins have been removed in the final rule. These matters will be addressed in upcoming rulemakings.

Appeals Procedures

The proposed core rules included an appeals section in part 72 that applied only to permits. Public comment was specifically solicited to determine if a broader appeals process located in a separate part would enhance the Acid Rain Program core regulations. In response to comments affirming the idea of both a separate and broadened rule to address appeals issues, part 72, subpart H, has been revised and relocated to part 78. This rule now addresses administrative appeals procedures for the entire Acid Rain Program.

Forms

In the proposed core rules, EPA introduced the concept of using standard forms to submit required applications and to report data and information for all parts of the Acid Rain Program. EPA proposed a number of forms for the regulated community to use in submittals regarding allowance transactions, compliance plans, and continuous emission monitors. The primary rationale for including these forms in the proposal was to solicit public comment on the overall forms approach to information transfer and to gather opinion on specific data elements requested on the forms. During the public comment period, EPA also held a special public meeting regarding these forms to obtain additional feedback.

The Agency received many public comments supporting the concept of standard form utilization; none received were opposed to the recommendation. Commenters indicated that the forms and instructions were generally sound as proposed, but numerous specific recommendations were offered suggesting how forms and instructions could be improved to eliminate redundancy and increase clarity and consistency. Some commenters stated that improved versions of the forms could be developed as experience is gained through their use. Other commenters questioned the need and usefulness of some data elements, and pointed out that some of the information requests by EPA were "nice-to-know" information or data that the Agency already had in its possession. Comments about data elements were carefully considered as the final substantive sections of today's rule were developed, and are discussed throughout the preamble, as appropriate.

As in December's proposed rule, EPA will itemize in the final rule each of the information and data elements that must be submitted by the owners and operators of an affected source to a permitting authority. While specific forms are not part of the rule, form content will continue to be governed by the rule, which enumerates information requirements.

Commenters and EPA agreed that forms should be removed from the final rule. Not doing so would mean even simple revisions to forms would require rule changes. Since many of these forms will be used throughout the life of the program (and some not utilized until Phase II), the opportunity to easily incorporate the experiences of Phase I permit issuances could significantly benefit implementation of the Acid Rain Program in Phase II. Commenters also stressed that future developments in the field of electronic reporting would more easily be incorporated into the program if forms were not made a part of the rulemaking.

No later than the effective date of this rule, EPA will direct mail packages of standard forms to the owners of all Phase I sources. These packages, with instructions, contain permit forms, monitoring plan forms, and certificates of representation. The certificates of representation will be sent to owners of Phase II sources in the event they wish to certify their representative now. Owners and operators are encouraged to certify as soon as possible in order to fully participate in allowance activities such as auction and sale (see the Discussion of Changes to part 73 for further discussion). The form for an application for a Phase I extension will be sent to those owners who have indicated interest in this compliance option. Any other interested party may obtain the packages of forms and instructions by calling the Acid Rain Hotline.

The preamble that follows outlines the major changes that the proposed rules have undergone since their publication in December 1991 and discusses public comment.

III. Changes to Part 72—Permits

A. Structural Changes

(1) Introduction

EPA received a large number of public comments regarding part 72. The general thrust of many of these was that the proposed rule needed to be simpler and more coherent. In response to these suggestions, EPA has made many revisions to part 72 that are designed to enhance readability and understanding. Because a substantial number of the changes made to this rule are structural and not substantive, the preamble addressing part 72 is divided into two sections, the first summarizing structural changes (streamlining efforts, relocations of sections, deletions, etc.) and the second addressing substantive revisions made to the rule.

(2) General Provisions

The general provisions section in proposed subpart A of part 72, which formerly applied only to the permits rule, has been modified and now applies, for the most part, to the entire Acid Rain Program. Provisions regarding Acid Rain Program definitions, measurements, abbreviations and acronyms, federal authority, state authority, applicability, standard requirements, availability of information, and computation of time that were located in various places in the proposed rule have been consolidated and are now included under this subpart. This modification promotes consistency among the parts of the rule and eliminates unwarranted redundancies.

(3) Definitions

Definitions for the Acid Rain Program have been combined into a single definitions section (§ 72.2) for 40 CFR parts 72, 73, 75, 77, and 78. Some definitions have also been revised to enhance the clarity of the regulatory text. Terms whose definitions did not differ from common English usage (e.g., "calendar year") have been deleted. Conversely, some terms whose definitions include a common meaning but that possess specific connotations regarding the Acid Rain Program have been clarified or removed from the definitions section when the textual context of the rule suffices in conveying the meaning of the term.

A number of definitions have also been eliminated or streamlined because they articulated substantive requirements that were more appropriately denoted in pertinent sections of the rules. Definitions redundant with substantive provisions of the rules have been deleted. The following table lists terms removed from the proposed rules glossary and, where applicable, their location within the text of the final rules.

Acid rain compliance option.	part 72, subpart D
Acid Rain permit application.	part 72, subpart C
Administrative permit amendment.	part 72, subpart H
Alternate authorized account representative.	§ 73.33(d)
Alternate designated representative.	§ 72.22
Applicable requirement of the Act.	Title V, § 70.2
Approved compliance plan.	part 72, subpart D
Automatic permit amendment.	part 72, subpart H
Complete permit application.	§ 72.50
Continuous	§ 72.2 (definitions of CEMS & COMS)
Control unit	Streamlined definition, see also § 72.42
Designated representative.	Streamlined definition, see also § 72.20
Determination of completeness.	§§ 72.61 and 72.72(b)(1)
Dual span system	part 75
Energy conservation measure.	§§ 72.43 and 73.81
Fast track modification.	part 72, subpart H
First-in, first-out accounting basis.	§ 73.35(c)(2)
Load management	§ 73.81(b)(4)
Monitor data availability.	part 75
Non-utility unit	section 402(25) of the Act
Path continuous emission monitoring system.	part 75
Permit modification	part 72, subpart H
Phase I extension unit.	part 72, subpart D
Proposed compliance plan.	part 72, subpart D
Ranking application	§ 72.42
Reduced utilization through energy conservation.	§ 72.43
Reduced utilization through improved unit efficiency.	§ 72.43
Renewable energy generation.	§ 73.81(c)
Renewable energy input.	§ 73.82(a) (12) and (13)
Repowering extension period.	§ 73.44
Sulfur-free generator	§ 72.2 (definition of sulfur-free generation)
Transferee account	part 73, subpart D
Transferror account	part 73, subpart D
Transferror unit account.	part 73, subpart D
Uncontrolled emissions rate.	§ 72.42 and part 75
Use allowances	§ 73.35

The definitions portion of the final rules no longer includes separate definitions for terms that are composites of separately defined terms. For example, the proposed definition for "existing affected unit" was deleted from the final rule since the terms "existing unit" and "affected unit" are defined separately.

One commenter asked that the rules include all statutory definitions applicable to the Program. Although sources should continue to refer to those definitions, § 72.2 lists statutory definitions only for those statutory terms utilized within the rules.

Some rule and terminology revisions have necessitated the redefinition of certain terms. For example, the term "Phase I affected unit" has been revised to read "Phase I unit" throughout the

rules since all Phase I units are affected units.

(4) Deletions and Relocations

A number of the provisions proposed in this subpart have been deleted or moved to other sections. For example, the provisions of the prohibitions (§ 72.8 in the proposed rule) and signatory requirements (§ 72.9 in the proposed rule) sections are, for the most part, now located in § 72.9 (standard requirements), § 72.20 (authorization and responsibilities of the designated representative), and § 72.21 (submissions) of this rule.

(a) Common stacks. Section 72.50 of the proposed rule described special provisions for units with common stacks. Because common stacks are also addressed in part 75 of this chapter, this section was deleted from part 72; requirements that are not redundant have been incorporated into the common stack provisions of part 75. The portion of the preamble covering part 75 discusses public comment on and changes made to the common stack provisions of that rule.

(b) Appendices A & B. Part 72 as proposed contained two lists of affected units: Proposed Appendix A (which listed all Phase I units, had a blank column for their Phase I allocations, and stated the units' 1988 and 1989 SO_2 emissions) and proposed Appendix B (which catalogued Phase II units and allocations). Both have been removed from the rule.

Proposed Appendix A was removed because the list of Phase I units and their allocations has now been promulgated in Table 1 of § 73.10(a) of this chapter with some corrections. In addition, some commenters objected to the figures for 1988 and 1989 SO_2 emissions. Those figures are needed only for those Phase I units involved in a Phase I extension plan and, under the final rule, must be submitted as part of the early ranking application or Phase I extension plan. Comments concerning 1988 and 1989 SO_2 emissions are addressed in section B(5)(c)(ii) of the part 72 preamble, and any remaining comments on proposed Appendix A will be addressed in the rulemaking on subpart B of part 73 of this chapter.

Proposed Appendix B was removed from the final rule because a large number of requests for revisions to proposed Appendix B were received. A more comprehensive and accurate list of existing Phase II units and allocations was proposed, and will be finalized, in Table 2 of subpart B of part 73. All comments on the inclusion or exclusion of specific units in proposed Appendix B will be considered in that rulemaking. See 57 FR 29940, 29965–30024, July 7, 1992.

It should be noted that the final rule contains new appendices that are unrelated to proposed Appendices A and B. Final Appendix A contains the methodology for annualizing emissions limitations. Final Appendix B contains the methodology for converting SO_2 emissions limitations to lb/mmBtu. Final Appendix C contains the methodology for calculating annual tonnage of SO_2 emissions. The methodologies in these final appendices are from the NADB Version 2.1 Technical Support Document.

(c) Reproposals. EPA has determined that further consideration is needed in order to properly draft some provisions originally proposed in the applicability portion of the rule. These provisions concern cogeneration units, new independent power production facilities, and qualifying facilities. The reproposals were included in the proposed rules for allowance allocations and reserves (parts 72 and 73). See 57 FR 29940, 29944–47 July 7, 1992.

The reproposed provisions will be incorporated into this part when promulgated in final form. Public comments received in response to the December 3, 1991 proposal will be addressed in the final rulemaking for these provisions.

(d) Addresses. Addresses for submissions to the Acid Rain Program have been eliminated from the rule so that changes to the addresses will not require a rule change. Appropriate addresses for submissions will be communicated in guidance, forms packages, or separate Federal Register notices as the need arises. EPA headquarters and regional addresses are listed and updated in 40 CFR 1.7.

(5) Combined Subparts and Sections

EPA has removed two subparts of proposed part 72. As mentioned in the overview, subpart H (appeals) has been removed and is now part 78. In addition, the provisions of proposed subparts F and G have, in large part, been combined in the final rule in subpart F. This should not be interpreted as a substantive change since both proposed subparts addressed essentially the same subject, i.e., federal permit issuance procedures in Phase I. All procedures for issuance or denial of a Phase I Acid Rain permit are now located in subpart F of the final rules. Some of the few requirements that were not redundant have been moved to other sections in subpart A or subpart C of the final rule.

Proposed subpart I has been renamed subpart G, but still governs implementation of Phase II of the Acid Rain Program. Subpart G sets out criteria for State operating permit program approval under title V of the Act, which augment or replace criteria set forth at 40 CFR part 70.

Proposed subpart J is now subpart H. In addition to clarifying and streamlining changes, two major substantive changes have been made to proposed subpart J. First, the Agency has eliminated proposed Option 1 under the fast-track modification procedure from the final rule. Second, the Agency has eliminated the requirement that notice be given to interested persons of all administrative amendments that occur under the Acid Rain Program.

Proposed subpart K, renamed subpart I in the final rule, still describes compliance certifications that a designated representative must submit for each affected unit. Because EPA believes that compliance certifications are critical to the smooth operation of the Acid Rain Program, this subpart was reorganized to promote clarity, while some certifications have been eliminated or made more specific. Comments concerning certifications for underutilization, Phase I extensions, and repowering and any major changes to provisions for such certifications are addressed in the respective portions of this preamble dealing with those compliance options.

B. Major Issues

(1) Exemptions (Subpart D)

(a) New units exemption. The proposed rule asked for comment on the possibility of providing an exemption from the Acid Rain Program for small new units. Many commenters requested that the Agency provide some kind of *de minimis* exemption for new units from permitting and all other requirements of title IV. Suggestions included size cutoffs ranging from 5 to 25 MWe, emission tonnage cutoffs such as those for Prevention of Significant Deterioration programs, and exemptions based on boiler or engine type. These recommendations relied heavily on the argument that monitoring costs would be overly burdensome to small utilities and small communities, that emissions from such units are very small and have negligible, if any, effect on the environment, and that the burden on sources and the Agency of permitting all such units would outweigh the benefit of such permitting.

Response: Although the Act does not explicitly provide for a *de minimis* exemption for new units, the Agency agrees with the commenters that such an exemption is appropriate. The

Agency believes that provision of a limited exemption is within its discretion in administering the Act. See *Alabama Power Co.* v. *Costle*, 636 F. 2d 323, 360–61 (D.C. Cir. 1979). Accordingly, EPA has included a provision allowing permitting authorities to grant a *de minimis* exemption in the new § 72.7 of the rule. The Agency reserves the right to reconsider this provision in future years, however, if the total emissions from all exempt units is significantly higher than projected. The rule provides an exemption from most title IV requirements (including the requirement to monitor emissions, hold allowances to cover emissions, and have an Acid Rain permit) for all new utility units that serve one or more generators, the nameplate capacities of which total 25 MWe or less, and that use fuels with a sulfur content less than or equal to 0.05% by weight.

The exemption for these units is based on the Agency's belief that emissions from such units will be *de minimis*. The vast majority of units of 25 MWe or less that use clean fuels are peaking diesel and dual-fuel (natural gas/diesel fuel) internal combustion engines or peaking combustion turbines (primarily natural gas). These units combust low sulfur fuels, such as natural gas and diesel fuel. In the near future, diesel fuel sulfur content requirements for motor vehicles will be reduced to 0.05% sulfur by weight, in accordance with the Act. This fuel will also be available for diesel-fired units and, indeed, may be the only fuel available to them in the future. The sulfur content of natural gas is significantly less than that of diesel fuel. Based on utility projections provided to the Department of Energy and EPA, approximately 170 new units under 25 MWe (including 22 combustion turbines and 148 diesel- or distillate-fired or dual fuel units) are expected to come on line between 1990 and 2000. All of these will likely be peaking units. Based on average heat input for units of this size and type in the NADB and AP42 emission factors, the projected new units will have total annual emissions in the year 2000 of approximately 4 tons of SO_2 and 800 tons of NO_x for the gas-fired units and 134 tons of SO_2 and 1,134 tons of NO_x for the diesel- or distillate-fired units. Because of the higher cost per MWe of operating a unit of this size and type rather than a larger unit burning less expensive fuels, it is extremely unlikely that these units will operate more hours than units of similar size and type have historically. Consequently, EPA has determined that the total SO_2 and NO_x emissions from new units under the exemption will be *de minimis*. EPA made this determination in light of the national cap of 8.95 million tons of SO_2 and the fact that these units have no NO_x limits under title IV and will provide information about their NO_x emission under title I.

This exemption will be of primary benefit to the small peaking diesel and dual fuel units that are operated by many small communities and will also apply to small combustion turbines of the same size, which also have extremely low emission levels. EPA rejected the option of exempting units by engine type, rather than by size and fuel, because a unit may switch to higher sulfur fuels. In addition, larger units will not necessarily have low emission levels. EPA also rejected the idea of exempting units on a case-by-case basis using predicted emissions because of the greater confusion, uncertainty, and regulatory burden that could result.

Although the statutory exemption for existing units that serve only generators with nameplate capacities of 25 MWe or less does not sum the nameplate capacities of all the generators served by the unit and require the total to be 25 MWe or less, the exemption for new units does sum in this manner. The Agency believes that since the new units exemption is based on a determination that emissions from exempt units are *de minimis*, a stricter standard is justified to ensure that the emissions reductions foregone are truly *de minimis*. Also, many of the units are reciprocating engines rather than boilers and therefore do not serve multiple generators. The Agency does not want to encourage future use of multiple generators with such units as a means of avoiding the requirements of title IV and therefore has applied the exemption based on the capacity of individual generators.

To obtain an exemption for a unit, the designated representative must submit a petition stating that the unit meets the criteria for the exemption, that the sulfur content of the fuel deliveries will be tested and information on the sulfur content of the fuel will be kept on site, and that the unit will comply with all requirements of the Acid Rain Program if operations change so that it no longer meets the exemption criteria. In addition, the designated representative must agree to surrender any allowances that the unit would otherwise be allocated under the Act for any years for which the unit will be exempted. Using the same procedures as those for issuing an Acid Rain permit, the permitting authority will then issue a written exemption delineating the exemption and the requirements applicable to the unit. The permitting authority's actions on exemptions are subject to the same right of appeal as actions on permit applications.

Because the Acid Rain Program is based on the calendar year (e.g., the program limits total annual emissions to allowances held at the end of the year), the exemption is effective on a calendar year basis. The exemption takes effect on January 1 of the year after the exemption is approved. An exempt new unit will not have to submit any further information or compliance certifications so long as it meets the exemption criteria. However, the unit must comply with any requirements of the Acid Rain Program that relate to the period during which the unit was not exempted. The exemption will have to be renewed every 5 years, as is an Acid Rain permit. This approach of requiring a renewal submission every 5 years and no annual certifications reduces the burden on the unit and the permitting authority while preserving the permitting authority's ability to keep track of the unit's compliance status.

The exemption will apply unless and until operations at the unit change so that the requirements are no longer met. Should the unit no longer qualify for the exemption, the owners and operators must comply with all requirements of the Acid Rain Program, including the requirement to submit a permit application. Monitoring requirements will take effect as for new units, except that the date on which the unit no longer qualifes for the exemption will be treated as the date of commencement of commercial operation. Although the permitting authority may not be able to issue an Acid Rain permit for such units by the time the unit is required to begin accounting for emissions, the permit application, once deemed complete, will be binding until issuance of a permit.

(b) Retired Units Exemption. The proposed permit rule did not discuss units that retire prior to their compliance deadline. Commenters, however, requested that the Agency provide relief from monitoring and permitting requirements for units that will be retired before the date that they must comply with Acid Rain Program requirements.

Response: The Agency agrees that full permitting is not necessary for retired units under certain circumstances. The Agency has therefore added a new § 72.8, which provides an exemption from some Phase II permitting requirements for any unit that retires

before the issuance, or the renewal, of a Phase II permit. The designated representatives of units that are affected during Phase I and that retire before issuance of a Phase I permit are not exempted from the requirement to submit a Phase I permit application for the unit. A Phase I permit is necessary because, if the unit is underutilized as compared to its baseline (e.g., by being shut down), it must meet the requirement of this part that the underutilization be accounted for. Moreover, a reduced utilization plan may have to be submitted for the unit.

The owners and operators of a unit retired under this section must appoint a designated representative. A designated representative is necessary not only because a petition for an exemption must be submitted, but also because allowances will continue to be allocated to the unit's account in accordance with 40 CFR part 73.

To obtain an exemption, the designated representative must submit a petition by not later than the deadline for submission of a Phase II permit application or, if the unit already has a Phase II permit, for reapplication for an Acid Rain permit. The petition must contain a statement that the unit is or will be retired and a requirement that the designated representative will submit a permit application for the unit before it may recommence operation. As suggested by a commenter, the application deadline is 24 months before the unit recommences operation. This deadline was chosen because it is consistent with the statutory deadline for new units to submit permit applications.

The permitting authority will act on the petition and issue a written exemption for the retired unit using the same procedures as those for issuing an Acid Rain permit. As with the new units exemption, the retired units exemption takes effect January 1 of the year after the exemption is approved. The unit must comply with all requirements of the Acid Rain Program related to the period before it was exempted. No annual submissions or certifications are required so long as the unit qualifies for the exemption, but the exemption will have to be renewed every 5 years. Both the retired units and new units exemptions will be handled by the States, upon approval of their operating permit programs under subpart G of this part and part 70 of this chapter. The costs of issuance and administration of the exemptions are indirect costs of the operating permit program.

This section addresses exemptions from permitting requirements only and does not specify the conditions under which a retired unit may be exempt from monitoring requirements. Those conditions are discussed in the portion of the preamble covering part 75 of this chapter.

(2) Definitions (Subpart A)

(a) *Fuels terminology.* Several comments were submitted concerning the categorization of units by fuel type. Because of the crosscutting nature of these issues, they deserve discussion here.

As many of the commenters noted, the fuels terminology used in the Act and the rules (e.g., "coal-fired", "gas-fired", and "oil-fired", "fossil fuel", "fossil fuel-fired", "coal", "coal-derived", "natural gas", and "fuel oil") affect the applicability of a wide range of Acid Rain Program requirements to affected units. For example, the repowering extension provisions in part 72 of the rules, and the NO_x requirements in section 407 of the Act, apply to "coal-fired" boilers only. Monitoring requirements can also vary depending on whether a unit is classified as "coal-fired", "gas-fired", or "oil-fired." Other provisions, such as a unit's baseline and allowance allocations, are dependent on the "fossil fuel" consumed.

Coal-derived fuel. Numerous commenters asked that the definition of "coal-fired" be revised by deleting the reference to "coal-derived" fuel. They noted that the reference would result in oil- or gas-fired units that burn any amount of coal-derived gas or liquid fuel being treated as "coal-fired" for purposes of the monitoring requirements of the Acid Rain Program. Several commenters noted that coal gas, although not in widespread use, "should burn cleanly" and should be treated as natural gas or methane. Others noted that coal gases and coal liquids are likely to be used in the future as supplemental fuels for gas- and oil-fired units that consume no solid coal. They argue that the regulation of such units as "coal-fired" would inadvertently inhibit advances in important coal-derived fuels technology.

The statute does not define "coal" or "coal-fired", although both terms are used throughout title IV (e.g., definition of "repowering", NO_x applicability). The legislative history, however, makes clear that "coal" fuel includes coal-derived fuels such as washed coal, liquified or gasified coal, and other conversions of coal. For example, the original Administration bill limited repowering to units burning "pulverized coal" (i.e., the conventional method of burning coal). This wording was changed to the more general term "coal-fired", thus implicitly expanding the universe of units potentially eligible for repowering extensions. As evidenced, for example, in the Senate and House committee reports accompanying S. 1630 and H.R. 3030 (Senate Rep. No. 101–228 at 292–93 (1989) and House Rep. No. 101–490 at 363 (1990)), Congress was aware that coal-firing options included a variety of coal-derived fuels.

Although some of the coal derivatives mentioned in the comments are expected to be cleaner than pulverized coal, it is unclear whether the developing technologies will become so standardized as to guarantee the removal of all sulfur components from these new fuel forms. Thus, whether a particular unit burning gasified or liquified coal will or will not emit substantial amounts of SO_2 or NO_x can only be determined with certainty by rigorous continuous emissions monitoring. Sources relying on such fuel in the future will be able to avail themselves of the authority in the Act and the rules to petition for approval of an alternative monitoring system. The state of the technology is not, however, so well established or uniform as to warrant a broad reclassification of such fuels and consequent exceptions to, for example, the monitoring requirements of the Acid Rain Program.

This rule, therefore, preserves the "coal-derived" reference in the definition of "coal-fired." In addition, the terms "coal" and "coal-derived" are defined to add clarity to the rule. The definition of "coal" is based on the definition in 40 CFR 60.41(f), the new source performance standards for coal-fired utility boilers. (The NSPS definition has been revised slightly to cite the correct ASTM and the incorporation by reference section.) The term "coal-derived" is defined in accordance with the legislative history references to include solid coal derivatives, liquified coal, gasified coal, and several other known coal derivatives.

The definition for the term "coal-fired" has also been revised to reflect the different characterizations that will apply under different parts of the Acid Rain Program. Thus, while for purposes of the part 75 monitoring requirements, any unit that burns any amount of coal or coal-derived fuel is "coal-fired", the classification for purposes of other parts of the Acid Rain Program is limited to units burning coal or coal-derived fuel as the primary fuel.

Gas- and oil-fired. One commenter asked that the rules address whether a "gas-fired" unit forced to convert to fuel oil due to a catastrophic interruption or

gas curtailment would be unavoidably held in violation of the monitoring requirements of the rule. The commenter suggested EPA adopt a five-year averaging approach for reclassification to avoid such forced non-compliance. EPA does not believe a specific rule provision is the best way to address such incidents. EPA has adopted an approach based on both the average and the annual figures over three years. In addition, the Agency has ample enforcement discretion in addressing violations caused by catastrophic events beyond the control of a unit.

Several commenters asked that the term "natural gas" (used in the definition of "gas-fired") be defined and that it include: Propane, landfill gas, digester gas, and methane; biomass; and coal-gasification. The final rules include a definition for "natural gas." The Agency, however, rejects the broad interpretation suggested by the commenters since it would not be consistent with the general scientific understanding of the term, nor with the Acid Rain Program's limited applicability to fossil fuel-fired units. The definition of "natural gas" does not, therefore, include landfill gas, digester gas, biomass, or gasified coal.

However, the definition of "gas-fired" was revised to include coal-derived gaseous fuel with a sulfur content no greater than that of natural gas, along with natural gas. Further, the definitions of both "gas-fired" and "oil-fired" have been revised so as not to preclude the use of non-fossil gas and liquid fuels as supplemental fuels for gas-fired and oil-fired units. These changes will allow essentially sulfur-free fuels, such as natural gas, landfill methane, or synthetic propane, but will exclude solid fuels such as wood or municipal waste since such fuels could not be monitored using the excepted methods of appendix D of part 75.

One commenter asked that the words "if any" be added at the end of the definitions for "gas-fired" and "oil-fired", to indicate that units do not have to burn more than one type of fuel. EPA agrees that the change would clarify the definition, and have revised the definitions accordingly.

The rules also include new definitions for "fossil fuel-fired", "fuel oil", "diesel fuel", "primary fuel" or "primary fuel supply".

In addition to the new fuels definitions, the final rules clarify the fuels treatment in the applicability and other provisions of each part of the rule, particularly in so far as a unit might be reclassified due to changes in fuel usage. For example, an existing unit's allowance allocations, based on historical data, will not change if the unit changes from coal-fired to gas-fired; a new unit could not avoid becoming affected by burning something other than a fossil fuel when commencing operation and subsequently switching to a fossil fuel; and the continued availability of a monitoring exception can change should a gas-fired unit begin combusting coal. For greater detail concerning fuel classifications, see the applicable portions of the preamble below.

(b) Utility units. The proposed applicability section identified affected units by referring to units as existing units or new units, or by describing the specific circumstances under which various units serve generators. Several commenters suggested changes to these terms to clarify that only utility units rather than all units are subject to the requirements of the Acid Rain Program.

Response: The term "utility" as defined in the Act specifies that only those units that currently produce, or at various times in the past produced, electricity for sale are utility units. Because the definitions of the terms "existing" and "new" used in the proposal and in the Act both include reference to serving a generator that produces electricity for sale, any unit that is not a utility unit would by definition be excluded by the proposed language. The requested clarification is, therefore, not a substantive change. The rule now includes the term "utility" in conjunction with the terms "existing" and "new" to clarify this point for the reader.

The proposal repeated the statutory definition of the term "utility unit" with a few minor changes. Paragraph (B) of the statutory definition was repeated in the proposal as follows:

"* * * a unit that was in commercial operation during 1985, but did not, during 1985, serve a generator that produced electricity for sale, shall not be a utility unit for purposes of the Acid Rain Program."

Commenters pointed out that this paragraph of the proposed definition needed clarification because the statutory language, read literally, describes a situation that on its face seems impossible. Since, under section 402(22) of the Act, "commence commercial operation" means "to have begun to generate electricity for sale," it is difficult to see how a unit that did not generate any electricity for sale in 1985 could be considered in commercial operation.

Response: EPA agrees and this paragraph of the definition has, therefore, been clarified in the definitions in today's rule and in the applicability section at § 72.6(b)(3). The Agency has interpreted this latter provision to mean that units that served self-generators in 1985 (i.e., did not generate electricity for sale) are not utility units as long as they continue to serve self-generators (i.e., do not currently generate electricity for sale). Thus, for example, an industrial boiler transmitting steam to a generator to produce electricity for public sale is a utility unit.

(c) Combined Cycle Units. The proposed rules requested comment on the treatment of existing combined cycle units. The proposal included combined cycle units without auxiliary firing in the definition of "simple combustion turbine," causing these units, if they commenced commercial operation before November 15, 1990, to be exempt from the requirements of the Acid Rain Program. Combined cycle units with auxiliary firing were not exempted from the Acid Rain Program in the proposal. Some commenters disagreed with the Agency's position and requested that combined cycle units with auxiliary firing also be exempted, based on the sulfur content of the fuel used. Other commenters supported the Agency's decision.

Response: The Agency has retained the proposed definition of "simple combustion turbine" because it is based on equipment configuration rather than operations. The complex array of operating scenarios under which combined cycle units operate and the relative ease with which operations can be adjusted would make a definition based on operations complex and difficult to implement. This rule, therefore, provides that existing combined cycle turbines that did not use auxiliary firing for commercial power generation in the baseline period (1985–1987) will be treated as simple combustion turbines and are exempt from the requirements of the Acid Rain Program under § 72.6 of the final rule. However, if such a unit after November 15, 1990, utilized firing, EPA will treat that unit as a new unit, subject to the Acid Rain Program. Such a unit will receive no allowances.

(d) Owner or operator. The definition of "owner or operator" has been revised to delete the words "designated representative." The proposed rule interpreted the statutory authorities, responsibilities, and duties of the designated representative as establishing a specific category of the "operator" role. *See* 56 FR 63009 (December 3, 1991). EPA solicited comment on an alternative reading of the statutory language that would

exclude "designated representative" from the definition of "owner or operator" in all cases. *See id.*

The Agency today reaffirms, with some refinements, the statutory interpretation set forth in the preamble. In most cases, the responsibilities of a designated representative will be narrower than those of an operator. Accordingly, based upon comments of the Department of Energy and others, EPA has determined that it would be inappropriate to broadly sweep all designated representatives into the definition of "owner or operator" as provided in the rulemaking proposal.

In some cases, however, the scope of the designated representative's responsibilities, as provided in the final regulations, would in fact be coextensive with those of an operator, and in those cases he or she would still be an operator. As discussed below, one such case is where there is a common designated representative for multiple sources lacking a common owner and operator and participating in a substitution plan. Thus, the definition has been revised to more accurately reflect the varied nature of the role of designated representatives under the Acid Rain Program by effectively providing that a designated representative is an operator only when his or her duties and responsibilities bring him or her within the ambit of that term.

(3) Designated Representative

Title IV of the Clean Air Act requires the owners and operators of each affected source to appoint a designated representative to act as a liaison between the source and EPA on matters concerning the Acid Rain Program.

(a) Designated representative requirements. (i) Universal requirement. In the proposal, EPA required that all sources have a designated representative. Several commenters suggested that EPA eliminate the requirement to have a designated representative where there is only one owner/operator at a source. The commenters argue that a designated representative is not needed in those situations and that the certification requirements are unnecessary and burdensome where there is a single owner/operator.

Response: The Agency disagrees. The designated representative is needed to simplify the Agency's administration of the Acid Rain Program and to ensure the accountability of an owner or operator for actions governed by the program by, *inter alia*, reducing the likelihood of inconsistent submissions by a source. In addition, requiring the source to interact with the Agency exclusively through one designated representative will permit the regulated community to exercise the flexibility in compliance provided under the Acid Rain Program while being assured that EPA will only act on a submission (e.g., an allowance transfer) that is authorized by the source. Thus, no matter how many owners or operators there are at a source, having a single designated representative will benefit both the regulated community and the Agency.

The Agency agrees, however, that one of the certification requirements in the proposed rules was unnecessarily burdensome on sources with single owners and operators. For sources with a single owner and operator, the Agency has eliminated the requirement that the designated representative send written notice of the agreement under which he or she is selected to that owner and operator, who undoubtedly already knows of the agreement. In the final rules, this requirement only applies to sources with multiple owners and operators.

(ii) Designation by source or unit. Several commenters objected to EPA's proposal requiring that each source have only one designated representative. These commenters argued that the language in sections 408(a) and 402(26) of the Act specify that designated representatives should be appointed by unit. The commenters also claimed that units, not sources are accountable for allowance transactions, compliance plans, monitoring reports, and excess emission penalties.

Response: The Agency agrees that most compliance requirements under the Acid Rain Program are imposed on a unit, rather than a source, basis. Nonetheless, the Agency believes that it is appropriate to require one designated representative per source. While units at a source may have some different owners and operators, there is generally one operator who coordinates operations of all the units and whose decisions concerning one unit may have consequences for the operation of other units. The requirement of a single designated representative per source reflects this operating reality. If units at a source were to have different designated representatives, the designated representative of a unit that was out of compliance might claim that the violation was caused by actions at another unit, whose separate designated representative might dispute the claim. The Agency does not believe that it should become involved in these kinds of disputes among units when it assesses compliance with the Acid Rain Program. Therefore, the Agency is requiring that only one designated representative be certified per source. Under this approach, the designated representative will resolve such disputes and will balance the needs of all of the units at the source in order to facilitate compliance by all units whenever possible. This also minimizes the possibility of inconsistent submissions concerning the different units at the source.

(iii) Daily notice requirement. Some commenters objected to the requirement that the designated representative give daily notice for two weeks by publication in a journal of national and general circulation of the agreement by the owners and operators appointing him or her, particularly where there is only a single owner or operator.

Response: Despite these comments, the Agency believes that this requirement is necessary to ensure that all persons that might consider themselves to be owners and operators of a source have the opportunity to learn of the selection of the designated representative. Without public notice, only those persons whom the designated representative believes are owners or operators will get notice of the selection, i.e., through written notice by the designated representative. In order to reduce the potential cost of providing public notice, the Agency modified the rule to require notice for 7 days in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general notice. The provisions concerning the type of publications to be used parallel certain public notice requirements in 40 CFR part 70. The Agency believes that, in light of the significant financial consequences potentially at stake in the selection of a designated representative, this requirement is not unduly burdensome.

(b) Designated representative's responsibilities. Several commenters suggested that EPA allow sources to delegate responsibility for non-allowance related submissions to a responsible official of the company, rather than requiring the designated representative to make all submissions under the Acid Rain Program. The commenters argued that this would provide them with more flexibility and would ensure the integrity of the submissions, by allowing the source to delegate responsibility to someone with personal knowledge about the particular information.

Response: The Agency has attempted to provide sources with maximum flexibility in the Acid Rain Program while ensuring accountability, but does

not agree that submissions may be made by someone other than the designated representative without adversely affecting the integrity of the program. Under section 402(26) of the Act, the designated representative represents the owners and operators in matters under the Acid Rain Program concerning the source, and, as discussed above, there are important reasons for limiting each source to a single representative. Interposing another person between him or her and the Agency would dilute his or her responsibility and in effect create multiple designated representatives for a source. Further, by leaving the responsibility to make submissions with the designated representative, the final rule has the salutary effect of making it clear that the designated representative should be aware of all submissions and, before submitting them, should inquire of persons with personal knowledge of the information in those submissions. Within these parameters the designated representative has flexibility to delegate duties (such as the preparation of submissions). However, under the final rule, the designated representative retains responsibility under the program for, and must sign and certify, all submissions.

(c) Minority ownership issues. (i) Unanimous agreement on selection of designated representative. The Agency received numerous comments on whether the designated representative should be selected by unanimous agreement of all of the owners and operators. Opponents of that approach claim that requiring unanimous consent would result in EPA improperly interfering in existing commercial relationships and contracts. These commenters believe that existing contractual agreements provide the means of resolving potential disagreements among multiple owners of a unit and that it would be counter-productive to require unanimous consent because it would embroil EPA in commercial disputes and, contrary to EPA policy, would supersede existing agreements in some cases.

Other commenters claim that requiring unanimous agreement is necessary to protect minority owners from "tyranny of the majority." Minority owners are concerned that they will be frozen out of the choice of the designated representative, who will then have control over allowances that belong in part to the minority owners and who will exercise this control in a manner adverse to the interests of the minority owners. Minority owners are also concerned that the designated representative will be chosen over their objections and that the actions of the designated representative, over which they have no control, will result in noncompliance for which the minority owners will be liable.

Response: The Agency does not believe that it should require the designated representative to be certified by unanimous consent. Title IV does not explicitly authorize EPA to impose such a requirement. EPA does not believe that it should alter existing commercial arrangements absent express authorization from Congress to do so. (Some existing agreements among source owners, of course, may require unanimous consent). EPA's position is consistent with the approach taken in the Sanford amendment, which included what became sections 402(26) (designated representative definition) and 408(i) of the Act and which was aimed at "ensur[ing] that the existing relationship between the various parties with legal interests in an affected unit are [sic] preserved." (136 Cong. Rec. S3378, daily ed., March 28, 1990 (Senator Sanford)). In addition, requiring unanimous consent of all owners could give leverage to dissidents, allowing them to force majority owners into unreasonable concessions (which may or may not be related to the Acid Rain Program) simply to remove the objections.

(ii) Unanimous agreement on allowance decisions. Several of the commenters who supported unanimous consent in choosing the designated representative recommended that, at a minimum, EPA require that co-owners of a unit explicitly discuss and decide how to hold, use, and distribute allowances or apportion liabilities that might be incurred by the source. These commenters claimed that existing agreements, negotiated before allowances were created, do not confer adequate authority on the designated representative to handle allowances. These commenters assert that the Sanford amendment was designed to protect minority owners and that, under it, only a unanimous, new agreement, negotiated expressly to reallocate allowances, should be allowed to override the provision in section 408(i) that allowances otherwise be held and distributed in accordance with the ownership interests in the unit.

Response: The Agency agrees that section 408(i) was introduced to provide protection for minority owners without burdening EPA "with the responsibility of using scarce resources to rigorously examine the relationship between various parties whenever there are multiple holders in a unit." (136 Cong. Rec. S3379, daily ed., March 28, 1990 (Senator Sanford)). Since the section 408(i) protections are to be applied by the parties and, if necessary, the courts, the Agency has decided not to go beyond the specific requirements of section 408(i). Instead, the final rules incorporate the statutory language requiring allowances to be distributed in proportion to legal, equitable, leasehold, or contractual reservation or entitlement in the absence of a contract expressly providing for a different distribution. EPA will leave it to the parties involved to apply this provision and determine whether and under what circumstances a unanimous, new agreement is appropriate. The Agency believes that this approach gives minority owners the protection that they were granted in the Act, while preventing EPA from becoming embroiled in ownership disputes.

(iii) Limiting designated representative's discretion. Several commenters also suggested limiting the discretion of the designated representative in certain matters in order to protect minority owner interests. For example, commenters suggested that EPA: Require an agency relationship to be established between the designated representative and all co-owners; limit the ability of the designated representative to use allowances belonging to the joint owners or to sell allowances without express authorization from co-owners; require co-owners to enter into agreements concerning the holding and distribution of allowances; and take a more active role in oversight of the actions of the designated representative.

Response: The Agency has rejected these suggestions because they would require EPA to review and alter existing commercial arrangements, and oversee new arrangements, in the utility industry, a role for which EPA has neither the necessary expertise nor express statutory authority. The Agency's approach concerning section 408(i) of the Act preserves the minority owner protection granted under the Act.

(iv) Freezing allowance accounts. EPA asked for comment on whether it should freeze allowance accounts in the event of a dispute over the actions of the designated representative. Numerous commenters objected to EPA's proposal not to freeze allowances, claiming that a freeze would better protect against the trading of co-owner's allowances without their express authorization and would further ensure compliance. Other commenters supported EPA's proposed approach of not freezing allowances because it avoids having EPA become embroiled in private disputes among joint owners. These commenters believe that aggrieved multiple owners have

adequate protection through their commercial agreements and through the courts.

Response: The Agency has decided not to include in the final rule any provision requiring the freezing of allowance accounts in the event of an allowance dispute. The Agency believes that such a provision would undermine the functioning of the allowance market, which depends on the ability of third parties to rely on the full effectiveness of the recordation of an allowance transfer.

Freezing accounts automatically whenever any owner or operator claimed there was an allowance dispute would be extremely disruptive to the allowance market. Allowance trading could be disrupted frequently and at any time. Any majority or minority owner or operator could use such "claims" to force unable concessions. Providing for routine freezing of accounts where a claimed dispute seems meritorious would require EPA to evaluate the merits of disputes. Such routine evaluation of disputes is beyond the expertise of the Agency.

However, in § 72.4 of the final rule, the Agency reserves the right to take action (e.g., with regard to the Allowance Tracking System) in extraordinary circumstances that require action to ensure the orderly and competitive functioning of the allowance system. In addition, of course, parties may obtain injunctive relief, where appropriate, from the courts.

(v) Liability of owners and operators. Many commenters objected to provisions in the proposed rule that imposed liability on all owners and operators of a source or unit for violations of title IV of the Act and the regulations. The commenters pointed to language in the proposal concerning joint and several liability for owners and operators for violations of title IV requirements. They argued that the Act does not give the Agency authority to impose joint and several liability. In addition, commenters also objected to the preamble discussion of shared liability as an attempt to impose joint and several liability without authority.

In particular, the commenters argued that under title IV, liability for violations could only arise for persons who exercised operational control over the affected source or unit. Many utility units subject to Acid Rain Program requirements are owned by several entities, some of which possess minority ownership interests in the unit or source. They argue that existing contractual arrangements often cede responsibility for operational control, including compliance with environmental laws, to the majority owners. Due to these pre-existing contractual arrangements, commenters contend they lack any operational control sufficient to exert any influence on compliance with title IV requirements. In addition, commenters claimed the Agency unlawfully relied on section 408(i) of the Act to impose responsibility for compliance with title IV requirements on minority owners. These commenters suggested that EPA should amend the proposal to exempt minority owners from liability.

Response: The Agency does not agree that the final rule should exempt minority owners from liability but does agree that all provisions in the proposal that expressly establish joint and several liability on the owners and operators of an affected source or affected unit should be removed. The question of the liability of a specific owner and operator is best left to case-by-case determination in the context of enforcement against specific violations, rather than being resolved in the abstract in a rulemaking.

On one hand, various sections of title IV impose obligations on owners and operators without distinguishing between majority and minority owners or owners that are not operators. (See sections 408(h), 409(f), 411, and 412(e) of the Act). Moreover, by virtue of an ownership interest in a business or property, an owner may exercise influence over operation of a facility and help foster compliance with environmental laws. This may be true even if the owner cannot exercise unilateral authority or significant control over operations. It is important to encourage oversight of activities at one's business or property and discourage tacit approval or willful ignorance of illegal activities that threaten the environment.

On the other hand, the Agency does not blindly enforce against all parties regardless of their level of awareness, control, and responsibility for violations of the Act. EPA focuses enforcement efforts on those parties most truly culpable for violations. EPA and the courts look to the culpability of parties in determining liability and assessing civil penalties.

The Agency, therefore, has removed from the final rule language that expressly imposes joint and several liability on all owners and operators and is leaving the question of liability to case-by-case determination in proceedings before the Agency and, ultimately, the courts.

(vi) Liability of designated representative. Several commenters expressed concern that a designated representative would be liable, under the proposal, for violations by owners and operators.

Response: As a general matter, EPA expects that its civil and administrative enforcement actions under the Acid Rain Program usually will focus on the owners and operators of affected units that do not adhere to emission limitation requirements under the program (sections 404 and 405 of the Act). Designated representatives also have responsibilities under the Act and would be liable for violations of those responsibilities. The Act, at section 402(26), defines the designated representative as a responsible person authorized by the owner or operator to represent the owner or operator as to certain matters, including, for example, holding and transfer of allowances (section 403) and submission of and compliance with permits and compliance plans and related documents (sections 408(c)(1) and 408 (h)(1)).

It is EPA's statutory interpretation that a designated representative is not liable for acts or omissions that are not within the scope of his responsibility as designated representative. Under the Act, owners and operators shall be fully liable for the emission limitations (sections 404(a) and 405(a)) and monitoring requirements (section 412) for an affected unit and are responsible for operating the unit in compliance with those requirements. A designated representative would not be subject to liability for a unit's noncompliance with those requirements, except to the extent that the designated representative is an owner, an operator, or has control over the operation of the affected unit, or has been authorized by the owner or operator to ensure compliance with those provisions. Accordingly, where a particular violation resulted from acts or omissions that are within the scope of the designated representative's responsibilities, he will be subject to liability for that violation.

(4) Phase I Substitution Plans (Subpart D)

Section 72.41 of this regulation implements section 404 (b) and (c) of the Act, which give the designated representative the option of submitting a substitution plan. Under a substitution plan, the designated representative of a Phase I unit identifies affected units (i.e., Phase II units) that would not otherwise be subject to Phase I requirements and requests that they become Phase I units subject to these requirements. Since the substitution units will then receive allowances in Phase I, this approach may enable the

designated representative to achieve compliance with the sulfur dioxide emissions limitations required during Phase I in a more cost-effective manner.

(a) Common owner or operator. Section 404(b) of the Act allows the owner or operator of a Phase I unit to designate, as a substitution unit, a unit "under the control of such owner or operator." In interpreting this statutory language, the proposed rule stated that a designated representative is an operator and that a common designated representative for all units in a substitution plan would, therefore, fulfill the statutory requirement that the original Phase I unit and the substitution unit be under the control of the same owner or operator. The proposed rule also required that the units have the same designated representative regardless of any other common control.

Many commenters supported the proposed interpretation of the substitution provision and commended the Agency for providing flexibility. Some of these commenters also asked for clarification that a common designated representative would not be required if the units in a substitution plan had another owner or operator in common.

A few commenters disagreed with the Agency's interpretation. They felt that substitution plans should be limited to one operating company. They argued that Congress intended Phase I reductions to be achieved in the geographical areas of the country where the environmental effects of acid rain are most extreme (i.e., the eastern U.S. where most Phase I units are located).

Response: The Agency has upheld the proposed interpretation of the statute on legal and policy grounds. In general, a designated representative is not considered to be an operator. However, in some cases, his or her duties and level of responsibility can be equivalent to that of an operator. For example, in cases where the designated representative represents multiple sources without a common owner or operator that are participating in a Phase I substitution plan, the designated representative is responsible for coordination among the sources for purposes of submitting permit applications and compliance plans. In that case, the designated representative's responsibilities would be broad enough to bring him or her within the definition of operator because he or she would be responsible not only for determining that the compliance plans for the multiple units accurately reflect the provisions in the substitution plan, but also that the units comply with the substitution plan. See section 404(b) of the Act. The regulations provide (§ 72.41(b)(1)(i)) that the owners and operators of the units must act through a common owner, operator or designated representative. These types of important coordination activities and responsibilities make it appropriate to deem the designated representatives who perform them the equivalent of an "operator," and assure that the statutory concern regarding accountability will be met. See 56 FR 63015 (December 15, 1991). Accordingly, the statutory requirement in section 404(b) that a substitution plan involve a common owner or operator is satisfied.

Moreover, this approach offers utilities, particularly small utilities, flexibility to pursue least cost compliance. Small utilities would effectively be denied the flexibility available to larger utilities under the substitution provisions if participation were limited to a single operating company. A small operating company is less likely to have its own Phase II unit to designate as a substitution unit.

Although most Phase I units are located in the eastern U.S., Congress did not explicitly target a geographical area in identifying Phase I units, but instead used size and emissions rate as the criteria for identifying Phase I units. The Acid Rain Program clearly calls for nationwide reductions of sulfur dioxide without explicit requirements that the reductions be restricted to a specific geographical area. See 136 Cong. Record S17244, daily ed., October 26, 1990 and S16979, daily ed., October 27, 1990.

This rule also clarifies that units with different designated representatives will be acceptable in a single substitution plan, provided that they have another owner or operator in common. This approach is consistent with the Act, which does not require more than a common owner or operator. The rule clarifies that if an owner, operator, or designated representative is changed after a substitution plan is approved, the requirement to have a common owner or operator must continue to be met. If it is not, the substitution plan must be terminated beginning January 1 of the calendar year during which the change was made.

(b) "Unnecessary" substitutions. The proposed rule required calculations in a proposed substitution plan showing that the SO_2 emissions reductions obtained by all units in the plan would be greater than or equal to the SO_2 emissions reductions that would have been obtained by all such units without the plan. On its face, the proposed rule allowed calculations showing, under the plan, the substitution unit using all its allocated allowances and making no reductions and the original unit making 100% of expected reductions. The rule did not explicitly state whether such a situation, where no real substitution of emissions reductions was proposed, would be acceptable. Several commenters recommended that the Agency clarify that it will accept a substitution plan under which no transfer of reductions is proposed.

Response: The Agency has clarified in § 72.41(c) (3) and (4) of this rule to require that the total number of allowances allocated under a substitution plan not exceed the maximum amount allowed to be allocated to the substitution units under the rule; the allowances do not have to be allocated to or used at the original Phase I unit. This means that a substitution plan can be used solely for the purpose of making a Phase II unit subject to Phase I requirements. The Agency has taken this position because the alternative, i.e., allowing only those substitution plans that project a transfer of reduction obligations to the substitution unit, could be circumvented by the submission of plans projecting that one ton of SO_2 reductions be transferred. Since there is no obligation under the Act to actually carry out the projected transfer of emissions reduction obligations once the allowances are allocated under the plan and since the same total number of allowances will be allocated under a plan whether the transfer was to be one ton, 5000 tons, or zero tons, the Agency sees no reason to implement the substitution provisions in a manner that would require artificial projections and would lead to more burdensome paperwork requirements.

(c) Substitution plan allowance calculation. The proposal calculated the allowances allocated under each substitution plan based on the substitution unit's baseline multiplied by the lesser of the unit's 1985 actual SO_2 emissions rate, its 1985 allowable SO_2 emissions rate, or its most stringent federally enforceable allowable emissions rate at the time of application. Commenters presented opposing views on this requirement. Several commenters suggested that the Agency has no authority to limit substitution allowances to current federally enforceable emissions rates and that Congress was concerned about reducing emissions from 1980 or 1985 levels and not from current levels. Other commenters suggested that the Agency use current utilization at substitution units rather than their historical baseline in the calculation of

allowances. They argued that using this methodology would provide substitution units with allowances to account for growth at those units since 1985 and that credit for growth is justified.

Other commenters argued the opposite extreme, saying that any reduction required by law, State or Federal, should be considered a reduction that would have occurred in the absence of a substitution plan.

Response: The manner in which allowances for a substitution plan are calculated has been revised. Consideration of the most stringent federally enforceable emissions rate at the time of application has been eliminated in today's rulemaking. Only 1985 emissions rates will be included in the calculation.

The Agency's position on this issue hinges on interpretation of the requirement in section 404(b)(5) of the Act that emissions reductions under the plan be no less than without the plan. Section 404(b)(3) requires a proposed substitution plan to include the 1985 actual or allowable SO_2 emissions rate and makes no mention of the current allowable rate or current utilization. The Agency believes that this language in section 404(b)(3) strongly implies that the allowances allocated under a substitution plan are to be based upon the substitution unit's baseline multiplied by the lesser of its 1985 actual or allowable SO_2 emissions rate. This interpretation assumes that the reductions contemplated under the substitution plan are to be measured from 1985 levels and is generally consistent with the approach in sections 404 and 405 of achieving emissions reductions, by allocating allowances, from 1985–1987 levels. Any reductions in emissions rate made at a substitution unit since 1985 will not have resulted from title IV and will, thus, not be counted as reductions that would have occurred without the plan. The elimmation of current allowable rates from the calculation of substitution allowances is also responsive to the many commenters who were strongly opposed to EPA's proposal to annualize current allowable emissions rates using the procedures by which 1985 allowable rates were annualized for NADB.

Moreover, consistent with this interpretation, the 1985, not the current, utilization level of a substitution unit will be used in the calculation of allowances. Applying the concept of a 1985 starting point for both factors (emissions rate and utilization level) used to calculate reductions is internally consistent and follows the language of section 404(b)(3) of the Act. The Agency finds that the use of current data for utilization would not provide the overall reductions contemplated by the Act because it would provide allowances for growth at Phase II units. Finally, the use of well-established 1985–87 data not only provides more certainty that reductions will actually be achieved, but also facilitates implementation of the provision.

(d) Demonstration requirements. The proposal specifies procedures for demonstrating that a substitution plan meets the requirement of section 404(b)(5) of the Act that the plan "achieve the same or greater emissions reductions than would have been achieved by the original affected unit and the substitute unit or units without such substitution." The proposed procedures required the calculation of projected annual emissions reductions from each unit in the plan and the comparison of these reductions to those that would be achieved without the plan. Some commenters pointed out that the total number of allowances allocated under a substitution plan determines whether the total emissions reductions achieved under the plan will be adequate and that the distribution of the requested allowances among the original and substitution units is, thus, incidental.

The commenters suggested that the Agency should simply require calculation of the total allowances available under the plan and eliminate the requirement to calculate reductions to be obtained by each unit.

Response: The Agency agrees that calculation of the unit-by-unit reductions is unnecessary and has streamlined the procedures for demonstrating the section 404(b)(5) requirement accordingly. The rule limits the total number of substitution allowances allocated under the plan to the maximum number calculated to be available under the plan, i.e., an amount equal to the total tonnage the substitution units could have emitted if they were not under the plan and so did not have to make any emission reductions. This requirement fulfills the demonstration requirement because total reductions for the original and substitution units will equal what total reductions would be without the plan: 100% of expected reductions by the original unit and no reductions by the substitution unit under title IV. The rule then provides the designated representative the option to choose to have some or all of these allowances redistributed from the substitution units to the original Phase I units in the plan. If no redistribution is chosen, the designated representatives must simply indicate this in the application. The streamlined approach to this demonstration greatly reduces the burden of preparing a substitution plan. Allowances, of course, may always be transferred after they are allocated under the plan.

To further simplify the substitution plan, the Agency does not require that the original Phase I unit report its baseline, its 1985 actual and allowable SO_2 emissions rates, and its allowance allocation. This information has already been collected and appears in NADB and Table 1 of § 73.10(a). The Agency, therefore, has no need to require the source to report it. Further, although required to be reported under section 404(b)(4) of the Act, the substitution unit's proposed emissions rate under the plan is not required in the rule. Similarly, the substitution unit's projected emissions without the plan—a figure that is not mentioned in section 404(b)(3)—is no longer required. Because allocation of allowances under the plan is based on historical data, proposed or projected rates are not needed.

(e) NO_x applicability. The proposed rule stated that each substitution unit is affected for NO_x on the date that it becomes affected for SO_2. The final rule states only that each substitution unit will be affected for NO_x and defers specification of the deadlines and conditions to the future rulemaking on NO_x regulations to implement section 407 of the Act. Because substitution plans provide a lot of flexibility for sources to bring Phase II units into the program during Phase I, the implications for NO_x emissions could be significant. For this reason and because many related issues concerning NO_x requirements have not been finalized, the details of NO_x applicability for substitution units have been deferred.

(f) Termination of plans. Under the proposal, substitution plans may be terminated through an administrative permit amendment, provided that the designated representative surrenders the allowances allocated under the substitution plan for the years of the termination. The final rule clarifies this provision to specify that notification to terminate a substitution plan must be submitted to the Administrator by at least 60 days before the allowance transfer deadline applicable to the first year for which the termination is to be in effect. This should allow the revision of the permit and the deduction of allowances to take place by the allowance transfer deadline. The Agency believes that retroactive terminations limited in this way should

be allowed in order to maximize flexibility in compliance.

(5) Phase I extension plans (subpart D). Section 72.42 of this regulation implements section 404(d) of the Act. A Phase I extension plan allows the designated representatives of units that commit to install technologies achieving 90% reduction of sulfur dioxide to obtain a two-year extension of the deadline for meeting Phase I emissions reduction requirements by applying for additional allowances from a special allowance reserve. The designated representatives of units that will transfer their emissions reduction obligations to the units installing control technologies may also request reserve allowances.

(a) Early ranking procedure. Prior to the proposal, the Agency determined, in consultation with the regulated community, that the 3.5 million allowance reserve for Phase I extensions was likely to be oversubscribed. Because the Act specifies that the Administrator must act on each application in the "order of receipt," some applicants would, therefore, not receive reserve allowances. The appropriate method for distribution of Phase I extension reserve allowances thus became one of the most controversial issues encountered in this rulemaking. Faced with the prospect of a drawn out debate, the regulated community advised EPA that certainty regarding the chances of receiving Phase I extension reserve allowances at the earliest possible date was important. For this reason, the Agency proposed an early ranking procedure to determine the order of receipt of Phase I extension applications prior to submission of a Phase I permit application. A telephone queuing procedure was proposed as the method for ranking these applications.

The Agency received extensive comment on this issue from the regulated community, high sulfur coal interests, low sulfur coal interests, equipment vendors, Congressmen and Senators, and a few environmental groups. Almost all commenters urged the Agency to abandon telephone queuing. Even those commenters who disagreed on what the alternative should be agreed on this point. The most frequently cited reasons for eliminating telephone queuing were cost to industry and the Agency and concerns about the security of the queuing system.

On one hand, commenters who favored a pro rata distribution of Phase I extension reserve allowances to all qualified applicants, argued that telephone queuing or any other first-come, first-served procedure fails to implement the intent of the Phase I extension provision. They argued that the provision was meant to buffer the economic impact of title IV on those utilities and States that are most dependent on high sulfur coal. The intent, they claimed, was to encourage the installation of control technology. A pro rata approach would ensure that all qualified utilities would receive at least some share of the reserve allowances and would, thus, allow more of them to proceed with the installation of controls.

On the other hand, low sulfur coal interests argued that the language of section 404(d) of the Act does not allow for pro rata distribution and supported the Agency's proposal to act on applications one at a time on a first-come, first-served basis until the allowances run out. These commenters did not argue, however, that the proposed telephone queuing procedure was the best way to implement their recommended approach. Some of the first-come, first-served supporters suggested a lottery drawing instead, pointing out that the effect would be the same as that of a telephone queue, at much less cost to sources and the Agency and with fewer security concerns. Some commenters who supported a pro rata approach also indicated that a lottery drawing would be satisfactory if the Agency decided against pro rata.

Response: The Agency has considered all of these comments carefully and has determined that a lottery drawing is consistent with the statutory language and will be the least burdensome and most expeditious method to provide an early ranking of Phase I extension applications. A lottery is also the only approach that commenters from both points of view seemed willing to accept. This was an important factor in the Agency's decision since litigation on this provision would only delay the certainty that is so important to the regulated community.

The rule specifies that the Administrator will begin receiving early ranking applications on the 40th day after promulgation of this rule. Forty days have been provided so that sources will have adequate time to obtain and read the rule and to appoint a designated representative. All early ranking applications received on the same day will be deemed to be received simultaneously. If the applications received on any one day result in the reserve to be oversubscribed, a public lottery drawing will be held to determine the order in which to act on each application received on each such day. About two weeks will elapse between the time that the source is notified of the lottery and the day on which the lottery is to be held so that applicants will have the opportunity to negotiate among themselves or to drop their applications if desired.

The conditions on the rank order, once it is determined, remain the same as those proposed. Several commenters did, however, ask for clarification that an application would not lose its place in the rank order if the information originally submitted requires adjustments. Only complete early ranking applications will be given a rank order. An application that contains all of the requested information is considered complete and is not rendered incomplete by the need to correct later any of the information. Once a complete application is given a rank order, adjustments can be made without changing the rank order of the application. The addition of new control units will not, however, be considered an adjustment. Similarly, the inclusion or exclusion of transfer units will be allowed as an adjustment but the total number of Phase I extension allowances requested will not be increased. The addition of new control units or additional requested allowances to an existing application would have the same effect as permitting submission of a new application ahead of other existing applications. Allowing such changes to existing applications would therefore contradict the requirement that applications be considered in order of receipt.

Allowances will be awarded to each unit based on the information in the early ranking application. The allowances will not actually be allocated (i.e., they will not appear in each unit's subaccount) until a full permit application containing a Phase I extension plan has been acted upon by the Administrator and each unit's permit has been issued.

It must be noted that one utility has filed suit against the Agency seeking court intervention requiring EPA to rank its request for allowances based on the March 1991 submission date of the request. *Monongahela Power Co., et al. v. Reilly,* Civ. No. 91–137–C (N.D. W.Va). While the case remains unresolved, the possibility exists that EPA may, at some later date, be required to revise the ranking procedures.

(b) Qualifying Phase I technology contract. The proposal required a fully executed contract for construction of qualifying Phase I technology contingent only on the receipt of Phase I extension reserve allowances.

Several commenters found the proposed rule language specifying requirements for the qualifying Phase I technology contract to be unduly

restrictive. Commenters pointed out that section 404(d)(2)(B) of the Act states that the contract "may be contingent upon the Administrator approving the proposal" and does not restrict the contract to a single contingency. Many commenters also suggested that the proposed requirement for a single contract for qualifying Phase I technology does not reflect the complexities of such agreements.

Response: The rule language has been modified to reflect more closely the statutory language. Other contingencies are, thus, permissible. However, the contract must be a binding agreement between the parties for installation of equipment capable of at least 90% reduction of SO_2.

The rule language has also been modified to, consistent with the language in section 404(d)(2)(B), allow for multiple contracts. The rule still requires contracts covering activities up to and including construction of the main scrubber module or, in the case of precombustion or combustion technologies, construction of the primary components of the removal system.

In addition, the rule specifies that submission of full contracts for qualifying Phase I technology with the early ranking application and with the Phase I extension plan will not be required. Instead, a source may submit, for each contract, a letter agreement that includes: (1) Identification of the qualifying Phase I technology to which the contract applies, (2) the parties to the contract, (3) the date each party executed the contract, (4) identification of the units to which the contract applies, (5) a list identifying each provision of the contract, (6) any dates to which the parties agreed, (7) the total dollar amount of the contract, and (8) the signature of each party and the date that each party signed. The listed information is needed to review the Phase I extension and early ranking applications. Condensing this information into a brief, but binding summary will streamline EPA's review and will reduce significantly the volume of documentation required to be submitted by each applicant.

The rule also specifies that a copy of the actual contract must be kept on file, and must be sent to the Administrator upon request. This requirement is necessary because section 404(d)(2)(B) of the Act requires that each extension proposal provide a copy of an executed contract for the design engineering, and construction of the qualifying Phase I technology. Since all permit applications are placed in a public docket, the statutory provision has the effect of requiring the contract to be available to the public. The opportunity for public examination of the contract must, therefore, be preserved. Elimination of the requirement to submit the entire contract reduces the paperwork burden on the source and on EPA while maintaining the opportunity for public review.

(c) *Calculation of reserve allowances. (i) General concept.* The proposal asked for comment on the Agency's interpretation of the procedures for allowance awards to each unit under a Phase I extension plan. The proposal provides that each control unit may receive reserve allowances based on the lesser of the unit's average annual emissions for 1988 and 1989 or the unit's projected uncontrolled emissions for 1995 and 1996 regardless of when during the extension period the control technology is actually installed. The Agency asked for comment on an alternative interpretation whereby the control unit would receive allowances based on uncontrolled emissions only if the control technology was not yet installed. Under this scenario, the control unit would still get reserve allowances, but the number would be based on the difference between their basic allowances and the number of tons they would emit with the controls installed.

Most commenters supported the proposed interpretation, although some commenters preferred the alternative interpretation because it ties reserve allowances more closely to the actual operations at a unit. Many commenters also requested that the final rule clarify that reserve allowances for transfer units are to be calculated using the same principles as applied to control units.

Response: The rule maintains the interpretation for calculating reserve allowances that was proposed. The Agency believes that the intent of the Phase I extension provision was to allow qualifying utilities to operate, during the extension period, as they would have been able to operate without title IV and to bank that amount of allowances if they installed control technology prior to January 1, 1997. See 136 Cong. Record, S2532, daily ed., (March 9, 1990) (Senator Bond). Under this interpretation, all units receiving the extension are treated in the same manner throughout the extension period, regardless of whether they install controls earlier than required by the Act.

The rule also clarifies that reserve allowances for transfer units are calculated using the same principles as applied to control units. This means that transfer units also receive reserve allowances based on the lesser of their average annual emissions for 1988 and 1989 or their projected uncontrolled emissions, i.e., what emissions would have resulted from operation of the unit in the absence of title IV.

(ii) 1988 and 1989 average annual emissions. The proposal specified the 1988 and 1989 emissions to be used for each unit in the calculation of Phase I extension allowances in proposed Appendices A and B. These figures were based on data reported on EIA Form 767 filed in those years. The EIA data was analyzed by EPA using the methodology in the NADB Version 2.1 Technical Support Document, Appendix D at 2.

Some commenters disagreed with the figures published in the proposal.

Response: The Agency has removed proposed Appendices A and B, with the 1988 and 1989 sulfur dioxide emissions data, from the rule. Individual figures therefore can be revised without revising the rule. EPA, in reviewing Phase I extension applications, will generally rely on the designated representative's certification that the data is correct. If a dispute over the data arises during the permit issuance process, EPA will rely on whatever data EIA reports to EPA for the unit in question and will convert this data to an annual tonnage figure using the methodology in the document cited above, which methodology is now contained in the final Appendix C of this part.

The proposal also stated that allowances for control and transfer units would be limited not only to the average annual emissions for 1988 and 1989, but also to the most stringent federally enforceable allowable emissions limitation for those years. Thus, if a unit had been out of compliance in those years, it would not receive reserve allowances for the emissions above the compliance level. Commenters on this issue questioned both the Agency's authority to impose this restriction and the procedures that were proposed for the annualization of allowable emissions rates. Commenters from the regulated community argue that the Agency has no authority to consider allowable emissions in this context since section 404(d)(4) specifically provides for consideration of average annual emissions and makes no mention of allowable emissions. This contrasts with other sections of the Act (e.g., section 409(c)) that expressly refer to allowable emissions. Commenters also claim that the Agency lacks authority to use the annualization procedures specified in the Act for allowable 1985 emissions rates for the annualization of other emissions rates.

Response: Because section 404(d)(4) expressly limits reserve allowances by only the average annual emissions for 1988 and 1989, the requirement to limit reserve allowances to 1988 and 1989 allowable rates has been eliminated altogether.

(iii) Projected emissions for 1995 through 1999. The proposed rule specified that projected emissions for 1995 through 1999 at control and transfer units be based on projected annual utilization as reported on EIA Form 767 and projected emissions rate for each year. This emission rate could not exceed the most stringent federally enforceable allowable emissions rate in lbs/mmBtu.

Commenters objected to the use of the EIA form as a source of projected utilization data, both because it does not provide annual projections for the appropriate years and because using previously reported projections does not provide sources enough flexibility. Commenters suggested that EPA simply require "good faith" utilization projections and asked EPA to clarify that because these projections are used to calculate Phase I extension reserve allowances, they would not need to be revised once the Phase I extension plan had been approved and the allowances allocated.

Some commenters objected to restricting projected rates to the most stringent federally enforceable allowable emissions rate. In addition, although neither the proposed rule nor the proposed preamble explicitly stated that the most stringent federally enforceable rate used for comparison to the projected rate would be annualized, some commenters felt that annualization was implied. They disagreed with the requirement to express an allowable rate in annualized form rather than in the format in which it is enforced.

Response: The Agency agrees with the majority of commenters that the use of EIA Form 767 as a source for projected utilization figures is not workable. The final rule simply requires projected annual utilization for 1995 through 1999. EPA intends that these projections be good faith projections. In addition, as commenters suggested, these projections need not be revised once the Phase I extension plan is approved.

The final rule similarly requires projected uncontrolled or controlled emission rates for 1995 through 1999 (as applicable), and EPA intends that they be good faith projections. EPA maintains that any projected emissions rate that exceeds the unit's most stringent federally enforceable emissions rate promulgated as of the filing of the Phase I extension plan will, on its face, not be good faith. As with the 1988 and 1989 actual emissions, EPA will generally rely on the certification of the designated representative. Should a dispute arise during the permit issuance process, EPA will convert the unit's most stringent federally enforceable emissions rate at the time of application to lbs/mmBtu using the conversion methodology in the NADB Version 2.1, Technical Support Document, Appendix D at 2. This methodology is now set forth in the Appendix B of the final rule. If there are two or more applicable federally enforceable rates, the rates will be converted to lbs/mmBtu, but not annualized, and the lowest rate will be compared with the projected emission rate.

(d) NO_x applicability. The proposal stated that control units must comply with nitrogen oxides reduction requirements on the date that the unit shuts down to install the control equipment and that transfer units are subject to nitrogen oxides reduction requirements on January 1, 1995.

Many commenters pointed out that the proposal seems inconsistent with section 407(a) of the Act, providing that a Phase I extension unit is subject to NO_x requirements when it must meet SO_2 reduction requirements, and section 404(d)(1), postponing SO_2 reduction requirements for such units for two years.

Response: The Agency agrees. The rule states that both control and transfer units are subject to nitrogen oxides requirements on January 1, 1997 in accordance with section 407 of the Act and regulations implementing section 407.

The only caveat to this provision is that transfer units not transferring the total number of emissions possible (i.e., the lesser of average annual emissions for 1988–1989 or projected uncontrolled emissions during the extension) to a control unit will not be exempt from nitrogen oxides requirements during those years that the transfer is partial, unless the transfer unit is the last unit allocated allowances under the Phase I extension plan. If the designated representative is not requesting the full amount of reserve allowances for which a transfer unit might be eligible, then the unit is subject at least in part to the SO_2 reduction requirements under title IV (section 407(a)) and so is subject to applicable nitrogen oxides emissions limitations on January 1, 1995. This interpretation was necessary to prevent gaming whereby numerous transfer units would be attached to each control unit, only requesting a few reserve allowances for each and thereby making them all exempt from nitrogen oxides requirements. The Agency does not believe such widespread exemption from nitrogen oxides reductions was contemplated under this provision and has, therefore, explicitly prevented it. However, if a transfer unit is the last unit allocated allowances under a Phase I extension plan and cannot receive all of the allowances for which it is eligible, e.g., because the Phase I extension reserve is depleted, the unit will be exempt from nitrogen oxides requirements until 1997. In the latter case, the partial transfer is unavoidable and so should not disadvantage the transfer unit.

(e) Demonstration of 90% removal efficiency. The proposal required control units to demonstrate 90% removal efficiency for qualifying Phase I Technology on an average annual basis beginning upon commencement of operation of the technology. A requirement to perform a 30-day start-up test was also proposed.

The Agency received many comments on this provision. Many commenters claimed that the average annual demonstration was unnecessary since under section 404(d)(7) of the Act, control units must not exceed the projected tonnage emissions of sulfur dioxide in their permit application. Many commenters also suggested that the demonstration not be required beginning upon commencement of operation of the qualifying Phase I technology. They suggest that since, with the 2-year extension, the deadline for operation of the technology is January 1, 1997, the requirement to demonstrate 90% removal should not begin until that date. In addition, commenters argued that if 90% removal is to be determined on an annual average basis, as proposed, a start-up test that can be repeated until the end of the calendar year is meaningless and redundant.

Response: Section 404(d)(2)(E) states that the control unit must project the number of allowances expected to be necessary for annual operation after the qualifying Phase I technology has been installed. However, the requirement not to exceed projected tonnage emissions does not ensure that 90% control will be achieved since the limitation could be met by reducing load or by using a lower sulfur fuel. Because the statutory definition of qualifying phase I technology requires that the technology achieves 90 percent reduction and because this requirement is a condition for awarding reserve allowances that provide a substantial economic benefit at the expense of other units, the

Agency does not agree with the commenters who suggested that the provisions based on section 404(d)(7) of the Act provide adequate demonstration and that the proposed additional demonstration be removed. The Agency does agree that the requirement to demonstrate 90% removal should not begin until January 1, 1997 and has revised the rule accordingly.

The proposed demonstration has also been revised to eliminate the requirement to perform a 30-day start-up test. The Agency agrees with commenters that both tests are not necessary. The rule does, however, require the designated representative to submit, for informational purposes, a copy of the start-up test results upon which the vendor is released from liability for providing a technology through which 90% sulfur dioxide reduction is achievable.

(f) Failure to meet 90% removal efficiency. The proposal specified that Phase I extension reserve allowances would be allocated conditionally until 90% removal was demonstrated. Following the demonstration each year, that year's reserve allowances would be allocated. Failure to achieve 90% removal efficiency would result in the allocation of fewer reserve allowances than had been set aside for that unit. This failure to receive reserve allowances would be in addition to any allowances that the Agency would deduct, under section 404(d)(7) of the Act, for failure to meet the projected tonnage limit specified in the permit.

Several commenters argued that the Administrator does not have the authority to withhold reserve allowances in this manner and that if the Agency chooses to keep the 90% removal demonstration, reserve allowances should not be affected by failure to meet the requirement. In addition, several commenters have argued that the "conditional" allocation and subsequent removal of some reserve allowances for failure to meet the demonstration requirements would unreasonably limit the utility's ability to realize the economic incentives that reserve allowances were meant to provide.

Response: Section 404(d)(6) of the Act authorizes the Administrator to allocate reserve allowances to each control unit with qualifying Phase I technology (i.e., technology that achieves 90% reduction) for the years in which the technology is required. The Act does not specify the timing of this allocation. The Agency, therefore, has the discretion to withhold allocation until all requirements are met, e.g., until the technology achieves 90% reduction. However, the Agency has revised the proposal so that reserve allowances will be allocated when the Phase I extension plan is approved, but the failure to demonstrate 90% removal efficiency in a particular year will result in an appropriate deduction of allowances after the end of the year. The Agency has made this revision to provide those utilities granted a Phase I extension with more flexibility. However, if the Agency could not require such a deduction after the end of each year, the Agency believes that the statute would require the alternative approach of delaying allocation of reserve allowances each year until the annual 90% removal requirement had been demonstrated.

(g) Reallocation of returned allowances. The proposal did not explicitly address the issue of reserve allowances that might be returned to the Administrator. Several commenters asked the Agency for clarification on how these allowances would be used.

Response: The final rule specifies that any reserve allowances made available at any time will be allocated in rank order to the next application that still meets the requirements for a Phase I extension.

(6) Phase I Reduced Utilization Plans and Underutilization Requirements

The reduced utilization provisions arise from a statutory requirement in section 408(c)(1)(B) of the Act. This paragraph prevents a Phase I unit from circumventing its emissions reduction requirements by shifting load to units that are not subject Phase I requirements. The statute requires an up-front plan when a unit is planning to shift its load in order to reduce its emissions.

Section 72.43 of the final rule outlines the requirements of a reduced utilization plan and describes the circumstances that dictate its submittal. Subpart I delineates the procedures that are required by all Phase I units at the end of each year in Phase I. Specifically, § 72.91 contains formulas that each Phase I unit must use to (i) calculate its "adjusted utilization" to determine whether it was underutilized and (ii) calculate the extent to which it accounted for underutilization through a reduced utilization plan. A unit is underutilized if its "adjusted utilization" is greater than zero. Section 72.92 contains a sequence of accounting steps that are mandatory for any unit that cannot fully account for underutilization through a plan. These steps involve a series of formulas used to determine the number of allowances, if any, that must be surrendered as a result of a shift in load that resulted in increased emissions at a unit not subject to an emissions limitation in Phase I.

As a result of public comment, changes were made to the proposed regulations. While the intent of this section remains basically the same, the Agency believes that the changes more effectively carry out this intent.

(a) Reduced utilization planning requirement. The Agency does not believe that section 408(i) of the Act requires a unit to file a reduced utilization plan in all circumstances involving underutilization and load shifting. As discussed in the preamble of the proposal, this interpretation of section 408(c)(1)(B) is contingent on the Agency's ability to require a unit to surrender allowances under section 403(d) to account for the emissions resulting from certain load shifting. In the absence of the ability to require such surrender, the Agency believes that the statute would require application of section 408(c)(1)(B) to virtually all cases of underutilization in order to ensure that the emissions reductions mandated by the statute are achieved. See Senate Rep. No. 101–228 at 334 (1989). The Agency continues to reject this latter interpretation of section 408(c)(1)(B) of the Act.

Commenters presented different scenarios in which they argued that it was unclear whether the planning requirement applied. The majority of them involved utilities that were planning to comply by a means other than reducing utilization. As a result of this alternative method, the utilities' Phase I units would be underutilized.

Response: Section 408(c)(1)(B) requires an up-front plan where the owner or operator proposes to meet the requirements of that section by reducing utilization of the unit as compared with its baseline or by shutting down the unit. In applying this section, the Agency is distinguishing between knowing that incidental underutilization may happen and making it happen for the purpose of compliance. Under the Agency's interpretation, it is only those utilities that underutilize for the purpose of compliance that are obligated to file a reduced utilization plan, provided that all other underutilization is subject to the allowance surrender requirement.

(b) Economic dispatching. Of particular concern to the commenters was the uncertainty as to whether underutilization caused by economic dispatching will require a reduced utilization plan. Under the proposal, if a utility did not fall under one of the listed safe harbors (which could cover a utility that carried out economic

dispatching) and had factored in the value of allowances avoided, saved, or banked into its economic dispatching, EPA could deem the utility to be in violation of the planning requirement. The use of a dispatch order based only on operating costs, and not the cost of emitting SO_2, could exempt a unit from the section 408(c)(1)(B) planning requirement. However, this approach would defeat the purpose of title IV, which is to create an allowance market that assigns SO_2 emissions a value and thereby enables utilities to consider the value of allowances needed or saved, along with other operating costs, in making dispatching decisions.

Response: EPA has therefore modified its approach by explicitly including economic dispatching as a safe harbor from the planning requirement. This safe harbor applies whether the unit obtains compensating generation from within or outside the unit's dispatch system. It also applies where underutilization is caused by an order of a utility regulatory authority issued to achieve economic dispatching. In addition, the Agency has eliminated regulatory language suggesting that consideration of the value of allowances in dispatching indicates that there was an unlawful failure to plan. There will be no retrospective determination of violation of the planning requirement under § 72.43 if a unit is underutilized due to economic dispatch and surrenders allowances as prescribed in § 72.92.

(c) Indicators. The Agency received comments addressing the indicators that should be considered to determine on a case-by-case basis the applicability of the planning requirement in section 408(c)(1)(B).

Response: The Agency has clarified that these indicators will be used when a utility is not operating under a reduced utilization plan and cannot fully account for its underutilization under any of the safe harbors. In that situation, the Agency will consider the indicators and any relevant evidence and determine on a case-by-case basis whether there was a planning violation. In addition, as discussed, the indicators have been modified, consistent with the Agency's approach concerning economic dispatch.

(d) Nitrogen oxides requirements. Under the proposal, compensating units would not be subject to nitrogen oxide requirements of section 407 of the Act. EPA received comments both supporting an interpretation of section 408(c)(1)(B) that would result in only SO_2 requirements applying to compensating units, not NO_x requirements, and supporting an interpretation under which both SO_2 and NO_x requirements would apply. The comments reiterated the arguments set forth in the preamble on the proposal.

Response: Like the proposed rule, the final rule provides that designated compensating units that would not otherwise be subject to Phase I of the Acid Rain Program are not subject to the Phase I NO_x limitations. As the Agency stated in the preamble to the proposed rule, EPA considered two opposing views on this issue, and noted that textual arguments can be made from the statutory language to support either view. (For a discussion of these opposing views, see the preamble to the proposed rule at 56 FR 63022–63023 December 3, 1991). After considering the comments on this issue, EPA has determined to adopt in its final rule the interpretation that EPA proposed, because the Agency has concluded that this interpretation best implements Congressional intent. *See Chevron, U.S.A.* v. *Natural Resources Defense Council,* 467 U.S. 837, 843, 865 (1984).

EPA reached this conclusion based on its belief that, in enacting the reduced utilization provision of section 408(c)(1)(B), Congress was concerned with compliance with SO_2 emission tonnage limitations in Phase I. In enacting section 408(c)(1)(B), Congress was not addressing compliance with NO_x emission rate limitations. This is shown by the phrase in section 408(c)(1)(B) expressly providing that an otherwise unaffected compensating unit is to be deemed an affected unit under section 404, but omitting any mention of section 407.

Moreover, the legislative history is clear that Congress' concern in enacting section 408(c)(1)(B) was to prevent circumvention of SO_2 emission tonnage limitations. S. Rep. No. 228, 101st Cong., 1st Sess. 334 (1989). Section 408(c)(1)(B) does not refer to just any utilization reduction at a unit, which could also apply to the NO_x provisions of section 407, but only to a unit's utilization reduction *as* compared with its *baseline.* Reducing utilization below the baseline level is germane only to compliance with the SO_2 tonnage limitations and allowances. It is not a method of compliance with the NO_x limitations of section 407, which are emission rate limitations.

With regard to the SO_2 requirements, the baseline is the utilization level that the statute multiplies by 2.5 lbs/mmBtu to determine the SO_2 allowance allocations. Thus, a unit could seek to comply with Phase I SO_2 requirements by keeping its emission rate above 2.5 lbs/mmBtu and reducing its utilization *below its baseline.*

The baseline utilization level has no such significance for compliance with the NO_x rate limitations of section 407, since a unit's emission rate is independent of whether it operates at, above, or below its baseline utilization level. Furthermore, utilization reductions below baseline are not relevant with respect to compliance with the Btu-weighted average annual emission rate under a section 407(e) Phase I NO_x averaging plan. Nor are such reductions relevant with respect to the calculation of penalties under section 411 for the number of tons emitted in excess of a unit's NO_x emissions limitation requirement. Both of those provisions are concerned with the total amount of tons emitted during the past year, based on a unit's actual utilization during that year.

In summary, Congress' use of the baseline as the utilization reduction trigger for section 408(c)(1)(B) indicates that the provision is aimed only at utilization reductions for compliance with the SO_2 tonnage limitations, and consequently, that the NO_x requirements do not apply to compensating units.

(e) Sulfur-free generators. (i) Conversion of Kwh to mmBtus. In the proposal, EPA requested comment on how to convert kilowatt hours of sulfur-free generation into mmBtu. The conversion factor is used to calculate the amount of sulfur-free generation that accounts for underutilization (which is in mmBtus) at the Phase I unit. Several commenters suggested using 10,000 Btu/kwh as an average heat rate.

Response: Given the wide range of variation in heat rates among Phase I units, EPA rejects this approach as being unacceptably inaccurate. The more accurate method, which the Agency has adopted, is to use the heat rate of the unit reducing utilization. The same conversion method is used to convert Kwh savings from energy conservation to mmBtus and to determine how much load is shifted to a reducing unit by a compensating unit.

(ii) Benchmark year. Under the proposal, in order to receive credit for sulfur-free generation, the designated representative of the reducing unit had to demonstrate an increase in generation at that generator as compared to the previous year. The Agency received comments requesting a change in the benchmark year used to demonstrate that increase. All commenters objected to comparing the current year's generation with the previous year's generation. The commenters recommended using 1985–87 average

generation for comparison in a manner analogous to the use of baselines under title IV.

Response: The Agency agrees that the recommended approach is reasonable, considering that there is no intent under section 408(c)(1)(B) to penalize utilities that have shifted to sulfur-free generation since 1987. Therefore, under the final rule, a Phase I unit will not have to surrender allowances to the extent that it can demonstrate an increase in generation at a sulfur-free generator above the 1985–87 average generation and above any sales growth in the Phase I unit's dispatch system. Sales growth in the Phase I unit's dispatch system is used as a proxy for sales growth in the sulfur-free unit's system, which data may not be available.

(f) Energy Conservation. (i) Verification of energy conservation and improved unit efficiency measures. The proposal outlined a procedure under which a utility using energy conservation or improved unit efficiency measures would verify actual reductions for three quarters of a year. An estimate of fourth quarter savings would be added to the actual reductions to determine the amount to be claimed in the annual compliance certification report. Within 90 days of the end of the year, a verification of the fourth quarter savings was to be submitted. This approach required separate verification of the first three quarters and the last quarter. Moreover, commenters asserted that the proposed rule may not provide sufficient time for accurate verification. In addition, EPA received comment on the lack of rigor in, and consistency among, States' verification methods of verifying savings from energy conservation.

Response: In light of these comments and in order to be consistent with the 6-month verification period allowed in connection with applications for allowances in the Energy Conservation and Renewable Energy Reserve under part 73, the Agency has made some changes to the verification procedure. To promote accurate and economical verification, utilities using energy conservation and improved unit efficiency will make a good faith estimate of savings for the entire year in the annual compliance certification report. A confirmation report showing verified annual savings is not due to EPA until July 1 of the following year. Further, because of inconsistencies among States' verification methods, savings from energy conservation must be verified in accordance with requirements in the final part 73 (concerning verification for purposes of obtaining allowances from the Energy Conservation and Renewable Energy Reserve), which have been strengthened in light of this problem. See the portion of the preamble addressing part 73 for further discussion of this issue.

(ii) Return of allowances. The proposal required deduction of allowances where heat input savings resulting from the use of energy conservation or improved unit efficiency measures were overestimated for the fourth quarter. Commenters requested that EPA return allowances surrendered when the annual compliance certification report underestimated energy conservation savings under a reduced utilization plan. Commenters argued that deducting allowances for overestimates while not returning allowances for underestimates was unfair and would inevitably lead to consistent overestimation of conservation savings.

Response: The Agency has provided in the final rule for the return of allowances in the case of underestimated energy savings for the year as well as allowance deduction for overestimates. The final rule contains a procedure for determining whether differences between the estimated and verified savings result in the deduction or return of allowances and in a change in the compliance status of the unit (e.g., excess emissions) for the year for which savings were estimated.

(g) Definition of "dispatch system". Utility system is defined as a unit's utility operating company as listed in the NADB. In the proposed reduced utilization provisions, utility system was used as the universe of units for establishing parameters such as system-wide sales decline, the Phase I aggregate utilization test (i.e., the calculation of the net utilization of a group of Phase I units), and savings from energy conservation and improved unit efficiency measures. Commenters opposed the proposed definition of utility system, claiming that it does not consider the manner by which sources are centrally dispatched. Some comments suggested broadening the definition to include holding company, while others suggested a definition as broad as power pool.

Response: The Agency has adopted a new term, "dispatch system", and defined it in § 72.2 to include, at the discretion of the designated representative with certain conditions, an operating company, holding company, or power pool if they are centrally dispatched. Although the Agency is adopting this broad definition, this flexibility brings many complications. It must be understood that for verification purposes and to prevent double counting, all units within a given dispatch system must all apply the same definition of dispatch system and use consistent data for purposes of compliance with reduced utilization and allowance surrender requirements. If a group of units wants to adopt a definition of dispatch system that is broader than utility system, the designated representatives of those units that will be in the dispatch system must jointly submit an identification of that dispatch system, listing all units that agree to be treated as such a group. In addition, a dispatch system may be required at the end of the year to submit a report with certain dispatch system data. In order to ensure the use of consistent values, all the designated representatives of units in a dispatch system must certify together that the data is accurate and that their submissions for their respective units will be consistent with this data.

The Agency reserves the right to reject a unit's designation of a dispatch system broader than the utility system if the submissions of all units claimed to be in that dispatch system are not consistent. For example, if two designated representatives of units in the same dispatch system submit annual compliance certification reports with different values for dispatch system sales decline, all annual compliance certification reports received from any unit in that system will be rejected. At that time, each designated representative will be required to resubmit the annual compliance certification report with its dispatch system defined as the utility system. The Agency is adopting this approach because the most effective way of ensuring consistent submissions by all units in a dispatch system is to put the burden of ensuring consistency on those units.

Consistent with the approach of increasing flexibility by basing the reduced utilization provisions on the "dispatch system," the Agency has determined that a unit with multiple owners that is dispatched into more than one system should also have more flexibility. Each Unit has one utility system, i.e., the system of the utility that operates the unit, and without further flexibility, only that system (or a dispatch system of which the utility system is a part) could be considered for purposes of applying the reduced utilization provisions. Under the final rule, the designated representative of a multi-owned unit may petition the Administrator to apportion the unit so that an owner's portion of the unit is treated as part of the dispatch system

into which it is dispatched. An owner's portion of the unit is its percentage ownership interest in the capacity of the unit. The apportionment is only for purposes of calculating a unit's adjusted utilization and the number of allowances that must be surrendered. The designated representative of the unit remains responsible for surrendering allowances for the entire unit, and the deduction of allowances is still from the Allowance Tracking System account of the unit.

If the petition is approved, an owner's portion of the unit will be treated as a separate unit from the rest of the original unit solely for such calculations. Adjusted utilization will be calculated separately under § 72.91 for the owner's portion and for the remaining portion of the original unit. Most of the data used in the calculation will be apportioned based on ownership in the unit's capacity. Plan reductions will be treated in a manner determined by the Administrator on a case-by-case basis. This is because the specific facts of each case may affect how such plan reductions should be handled.

Similarly, where the petition is approved, the allowance surrender formula in § 72.92 will be applied treating the owner's portion of the unit as a separate unit from the rest of the original unit. The designated representatives of the unit and of all dispatch systems that include any portion of the unit must submit all reports required under §§ 72.91 and 72.92 and demonstrate that they are using properly apportioned data that does not result in any undercounting or double-counting. Where the designated representatives fail to meet their burden, the Administrator may require them to resubmit all reports and return to treating the entire unit as a single unit.

(h) Annual compliance certification report. (i) Basic approach of allowance surrender formulas. Under the proposal, generation compensating for underutilization of a Phase I unit was segregated according to whether the generation could be attributed to a known unit in order to determine how many allowances the Phase I unit should surrender. To the extent load was shifted to other Phase I units in the same utility system, no allowances would be surrendered for the unit's share of such a shift. If load were shifted to undesignated but known non-Phase I units, that utilization would be multiplied by the weighted emission rates of those known units. The product would be used to determine the number of allowances to be surrendered for those shifts. If the load was shifted to unknown non-Phase I units, the Agency proposed the use of a proxy for establishing an emissions rate, i.e., a current weighted average emissions rate for all non-Phase I units in the NERC region in which the Phase I unit was located. The Agency believed this to be a reasonable approach, considering that the NERC region was the most probable universe of sources from which compensating generation would be obtained.

Much of the public comment addressed issues concerning the allowance surrender formula and stated that the formula was confusing and unworkable as proposed.

Response: In light of these public comments, the Agency has determined that the basic approach in the proposal should be modified. Under the proposal, multiple Phase I units could claim compensating generation from a low-emitting, off system, non-designated unit. There would be no means of requiring all these units to agree on how to divide up such generation or of preventing double counting of such generation.

The final rule distinguishes compensating generation within a defined dispatch system from that provided from outside the dispatch system. Of course, a unit may adopt an expansive definition of its dispatch system. For a unit to be credited for compensating generation from a specific unit or sulfur-free generator (whether from within or outside the dispatch system), the compensating unit or sulfur-free generator must be designated. Otherwise, the unit surrenders allowances based on an appropriate weighted average emission rate. The total amount of underutilization for the dispatch system will be multiplied by an emissions rate that is the weighted average of the current dispatch system emissions rate and the 1985 NERC region emissions rate. These emissions rates are averages based on the emissions rates of Phase II units in the dispatch system and of non-foreign and non-Phase I units in the NERC region respectively. This is explained in detail below. The result is the number of allowances to be surrendered, reflecting certain adjustments for other Phase I units, dispatch system sales decline, and foreign sources.

(ii) Verification of compensating generation. Under the proposal, increased generation at designated compensating units in a utility system was counted in the Phase I aggregate utilization test for calculating the net underutilization of Phase I units in the system. Phase I units with underutilization would surrender allowances for their share of the net underutilization for the system. Under that approach, however, if there were more than one underutilization Phase I unit in the utility system, all such units would be credited with a portion of the generation at any designated compensating unit within that system. The Phase I unit that designated it would still surrender allowances based on its share of the net underutilization for the utility system. It was therefore necessary to devise a method whereby the Phase I unit designating a compensating unit would receive credit for all of the increase in generation at that compensating unit.

In the final rule, the designated representatives of the Phase I unit reducing its utilization and the compensating unit must certify that the amount of generation (in Kwhs) to be credited (after conversion to mmBtus based on the reducing unit's heat rate) to the reducing unit will be reflected (after conversion based on the compensating unit's heat rate) in calculating the utilization of the compensating unit. By adjusting each unit's utilization before determining net underutilization of the dispatch system, the designated compensating generation is attributed to the unit that designated it. This also prevents double counting of the compensating generation.

Compensating generation from sulfur-free generators designated by the reducing unit requires a different approach because these generators are not regulated under the Acid Rain Program. If a sulfur-free generator is in the same dispatch system as the reducing unit, then the reducing unit must demonstrate an increase in generation at that generator above any increase that resulted from sales growth in the dispatch system. This method essentially attributes all increases at the sulfur-free generator to the Phase I unit that designated it. If a Phase I unit has designated a sulfur-free generator outside of its dispatch system, the Phase I unit must, in addition, provide documentation showing that an amount of electrical energy at least equal to the amount of claimed compensating generation was actually purchased by the unit's dispatch system from the sulfur-free generator.

If the sulfur-free generator is providing compensating generation for more than one Phase I unit, inside or outside of the dispatch system, it is the responsibility of those Phase I units to claim in total only the amount of the increased generation at that sulfur-free generator and apportion that amount among themselves.

(iii) NERC-wide generation and emissions data. Under the proposal, NERC-wide information would have been used to calculate two factors in the allowance surrender formulas. First, the formulas used, as a proxy emissions rate, a current NERC-wide average emissions rate calculated using the annual average emissions rate for all non-Phase I units within a given NERC region. In addition, in response to industry input in the proposed rulemaking, it was agreed that there should be no allowance surrender to the extent that Phase I units might have compensated for a portion of the underutilization. In order to approximate this portion, a unit would establish what percent of its compensating generation came from unknown sources and what percent of total current NERC generation was produced by Phase I units. Multiplying the two percentages would approximate the fraction of emissions that should not be subject to allowance surrender. EPA requested comment on the feasibility of compiling this NERC-wide data for a given calendar year by the allowance transfer deadline for that year.

Several commenters stated that current, annual NERC-wide data could not be compiled within that time frame. Because of this problem, some commenters suggested that NERC-wide data for other periods (e.g., September 1–August 31 of the prior calendar year) be used.

Response: EPA now recognizes that, whatever period is used, it would be unduly burdensome to require that each unit calculate NERC-wide data on its own. Moreover, such an approach could well result in utilities within a given NERC region arriving at different calculations and data. To facilitate consistency within each NERC region, information for each region could be compiled by one impartial source. EPA considered acting as the clearing house for these yearly calculations. However, this approach was rejected as a result of experience gained in establishing baselines for the NADB. It has taken several years to resolve disputes over the data and publish final data.

In the final rule, the Agency has taken an approach that solves the timing, burden, and consistency problems. EPA has included in the rule the NERC-wide non-foreign and non-Phase I emissions rate and percent of non-foreign and non-Phase I generation for each NERC region for 1985, which are derived from the extensively reviewed, final data in the NADB. This NERC-wide data will be used to approximate the emissions resulting from, and therefore to determine the number of allowances surrendered for, compensating generation by units outside of the dispatch system. The methodology used to calculate these values is available in the docket.

(iv) Sulfur-free generators. Commenters requested that EPA expand the Phase I aggregate utilization test under the proposal to include non-designated sulfur-free generators in calculating net underutilization for the utility system.

Response: The Agency agrees in principle that there should be no allowance surrender to the extent that a unit can demonstrate that compensating generation was provided by a sulfur-free generator. Including sulfur-free generators when determining the net underutilization for the dispatch system would require a showing that such generators increased their generation above average annual 1985–1987 generation and after accounting for system-wide growth. In addition, designated representatives would be required to agree, before submitting their annual reports, on how to divide sulfur-free generation into designated and undesignated categories. These demonstrations would essentially duplicate those required at the end of the year where a plan is submitted. The burden of completing and submitting a plan designating a sulfur-free generator is minimal, and the plan can be submitted or activated any time at least 90 or 60 days respectively before the allowance transfer deadline. Therefore, to avoid unnecessary complexity in the rule and the implementation of the rule, the Agency requires in the final rule that to receive credit for increased generation at sulfur-free generators, a unit must designate the generators in the reduced utilization plan.

(v) Forced outages. The Agency wishes to clarify the confusion arising as a result of a typographical error in proposed § 72.409. Subsection (e) of proposed § 72.409 should have read, "To the extent the demonstrations required by paragraphs *(a)(1)–(2)* of this section do not account for the entire amount of unplanned underutilization," allowances must be surrendered consistent with the allowance surrender formula (emphasis added). Shifts in generation due to forced outage—like generation shifts resulting from economic dispatch—may result in increased SO_2 emissions at units not subject to the Acid Rain emissions limitations during Phase I and therefore must be subject to allowance surrender. This correction is reflected in the final rule.

Under the proposal, units would be required to submit information about every forced outage. This information included, but was not limited to, the cause of the outage, what steps were being taken to rectify the situation, and the extent of the underutilization that was attributable to that outage. Commenters claimed that the reporting requirements in the event of a forced outage were too burdensome.

Response: EPA is under a statutory obligation to require a Phase I unit to file a reduced utilization plan when the unit is shut down for purposes of compliance and so is underutilized. The Agency maintains that the reporting requirements in the event of a forced outage are necessary to prevent the circumvention of the section 408(c)(1)(B) planning requirement. For this reason, the information required under the rule to be reported concerning a forced outage is the same as in the proposed rule.

However, the Agency has modified the reporting requirements so that they apply to a smaller universe of forced outages. A given outage will trigger the reporting requirement only if the outage will be identified in the annual compliance certification report as a justification for unaccounted-for underutilization or if the outage is continuing and is expected to last longer than 4 months. This approach will reduce the reporting burden and provide information necessary to identify instances of potential circumvention. In all cases, underutilization resulting from a forced outage will be compensated for by allowance surrender according to the formulas in § 74.92.

(vi) Treatment of foreign generation. The preamble of the proposal stated that underutilization resulting in generation being shifted to foreign sources would be excluded from allowance surrender. However, the allowance surrender formulas did not actually deduct load from foreign sources in calculating emissions for which surrender was required. Therefore, in the proposal, the practical result would have been allowance surrender for these shifts.

The Agency requested comment on the treatment of foreign generation. Several commenters claimed that the intent of title IV is to regulate sources within the United States. Therefore, Phase I units that shift generation to foreign sources are allegedly under no obligation to surrender allowances for those shifts.

Response: The Agency believes that there should be no allowance surrender for shifts to foreign sources (i.e., Canadian sources), but for reasons different from those suggested in public comment. As a result of the U.S.-Canada

Air Quality Agreement, Canadian sources will be subject to an annual national sulfur dioxide emissions cap. If a Canadian source chooses to increase its output in order to sell to the U.S., it will have to account for those emissions in Canada. The resulting costs will presumably be reflected in the price the U.S. utility pays for the Canadian generation. Requiring allowance surrender by the U.S. utility would result in double counting of the costs of emitting SO_2 in Canada. Consequently, the final rule does not require allowance surrender for such shifts.

(7) Phase II Repowering Extensions

Repowering is the only optional compliance method available for compliance with sulfur dioxide emissions limitations during Phase II of the Acid Rain Program. A repowering extension provides a qualifying utility the extra allowances needed to cover its emissions during the time required to install a qualified repowering technology. Congress created this extension to encourage certain types of new, innovative clean coal technologies.

In § 72.44 of the final rule, the Agency has clarified certain provisions and some inconsistencies between the proposed rule and preamble. While many comments were received concerning the repowering extension, they addressed the same issues and presented many of the arguments discussed in the proposal. As a result, the Agency made few substantive changes to the original proposal.

(a) Definitions. (i) "Qualifying repowering technology". According to the proposal, a "qualifying repowering technology" must involve boiler replacement. While most commenters addressed this issue, they presented the same arguments as those discussed in the preamble of the proposed rule.

Response: EPA still maintains that the statute clearly mandates boiler replacement as a prerequisite for approval as a qualifying technology. The Agency reiterates that the failure to qualify for a repowering extension does not preclude a utility from employing a clean coal technology or other method of complying with Phase II emissions limitations.

(ii) "Replacement." In the proposal, the Agency stated that it would determine whether a technology involved boiler replacement on a case-by-case basis, using the test in 40 CFR 60.15 for "reconstruction" as general guidance. EPA requested comment on this approach. Several commenters objected to the proposed 40 CFR 60.15 test—which requires that new components cost over 50 percent of total cost to construct a comparable new facility—as too strict for innovative technologies. Other commenters claimed that the 40 CFR 60.15 test is not strict enough because it would not require 100% boiler replacement.

Commenters from environmental groups and one utility agreed with the Agency's proposed definition. They argue that the broader the definition of repowering, the greater the number of allocated bonus allowances breaking the 8.95 million ton cap during 2000–2010 and the larger the ratchet reducing non-repowering units' allowance allocations in Phase II.

Response: The Agency continues to believe that a case-by-case approach is warranted by the complex and intensely factual nature of the determination of whether a technology involves boiler replacement. Moreover, the 40 CFR 60.15 test strikes a balance between an overly broad interpretation that would increase overall emissions and an overly narrow interpretation that would limit the incentives under section 409 of the Act for innovative technology, and the test will therefore be used as guidance.

(b) Treatment of failed projects. The proposal mirrored section 409(b)(2) of the Act, which provides that if the repowering technology has been properly constructed and tested on such unit but fails to meet emission reduction limitations and is economically or technologically infeasible, the unit will continue to receive its extension allowances. This would permit the unit to be retrofitted or repowered with another control technology. Once the extension ended on December 31, 2003, the repowered unit would be limited to the standard Phase II allowance allocation. The Agency requested comment on the treatment of repowering projects that fail before they are completed and tested and whether and under what conditions a unit that did not complete construction should continue to get extension allowances.

Those commenters who maintained that a unit need not complete construction in order to continue to get such allowances suggested that, based on legislative history, EPA has the discretion to grant utilities extension allowances when a technology falls, or a utility decides to terminate the project, before construction and testing is completed. Commenters argued that EPA should use this discretion to allow utilities to continue to receive extension allowances when there has been a good faith effort to try to complete a project. Otherwise, these utilities would be forced to spend large sums of money to finish the project, which is doomed to failure, in order to receive the allowances.

Response: The Agency believes that "proper" construction and testing to determine if a project has failed does not necessarily require "completion" of construction. Thus, consistent with the legislative history, EPA has discretion to make case-by-case judgments of whether there was proper construction and testing of a given project. However, because repowering extensions will break the Phase II emissions cap, the Agency is under a statutory mandate to be frugal in granting the full repowering extension where the repowered unit is not completed. The final rule provides that to be considered properly constructed and tested, the project must be constructed at least to the extent to permit direct testing of the multiple combustion emissions from the operation of the repowering technology at nameplate capacity.

(c) Treatment of unused allowances. While section 409(c)(1) of the Act states that allowances are not transferable to any other source, this does not preclude a unit from transferring unused allowances to another unit at the same source. However, several commenters believe that a unit granted repowering extension allowances cannot transfer those allowances to any other units and should be required to return any unused extension allowances.

Response: Extension allowances are transferable between units at the same source. Nothing bars a transferee from transferring any allowances, freed up by that transfer, to other units at any source. Because there is no express statutory authority for EPA to require the surrender of unused allowances and any surrender requirement could be so easily circumvented, the Agency has rejected the commenters' approach.

However, the Agency has clarified the meaning of the bar on transferring allowances to other sources. The final rule bars the transfer of the extension allowances to any Allowance Tracking System account other than unit accounts of other units at the same source. Since allowances cannot be used for compliance unless they are recorded in the Allowance Tracking System, the bar on transfers should focus on transfers among Allowance Tracking System accounts. The language in the final rule will prevent direct use of the extension allowances by units at other sources.

(d) Repowering application deadlines. Section 403(a) of the Act requires the Agency to issue final Phase II allowance allocations (reflecting repowering extension allowances) by June 1, 1998. Under section 408(d), the Phase II

permit application, including the repowering extension, must be submitted by January 1, 1996 and the Phase II permit must be issued by no later than December 31, 1997. Under section 409(a), the owner or operator of an existing unit must demonstrate by December 31, 1997 that it meets the requirements for a repowering extension. Reflecting these constraints, EPA proposed a January 1, 1996 deadline for submitting the repowering extension plan. If conditional approval was sought, the approved plan could be activated any time on or before December 31, 1997. Further, the proposal sets a June 1, 1997 deadline for submitting the petition for approval of a repowering technology in order to allow the Agency 6 months to review and act on the petition before the December 31, 1997 deadline for action on the permit application. The Agency requested comment on the proposed deadlines. Several commenters claimed that certain non-statutory deadlines in the proposal were not justified.

Response: The Agency maintains that the proposed deadlines are consistent with the statute and necessary for the smooth and timely implementation of the repowering extension. In particular, if the repowering technology petition were not submitted until the end of 1997, the statutory deadline for permit issuance would be missed. For these reasons and the reasons stated in the preamble for the proposal, the deadlines are retained in the final rule.

(8) Acid Rain Permit Application and Acid Rain Permit (Subparts C and E)

Under section 408 of the Act, the designated representative of each affected source must submit a permit application, including a compliance plan that sets forth the methods to be used to comply with the requirements of the Acid Rain Program. The permitting authority reviews such applications, approves or disapproves the compliance plans, and issues or denies permits.

a. Permit application information available from other data sources. In the preamble to the proposed rule, EPA requested comments on whether the Agency should request information that could be obtained from other data sources. Commenters agreed that EPA should require all the information needed to issue the permit to be submitted on one permit application form, rather than attempting to obtain this information from other data sources.

Response: The Agency therefore will require all needed information to be submitted by the applicant. The Agency has, however, attempted to simplify and clarify the information requirements for the permit application. The final rule asks only for the information that is needed to write the permit; the Agency will not ask for extraneous information. The Agency believes that having clear and simplified permit application requirements will facilitate compliance by all affected units.

b. Data no longer required in permit application. (i) Project annual utilization. Several commenters objected to the requirement to provide projected annual utilization, as reported on EIA form 767, for units covered by the permit application. They pointed out that EIA form 767 data will not be available at the time the permit applications are due and will not provide all of the required projections. Furthermore, commenters questioned what EPA would do with the information.

Response: The Agency has reconsidered the need for this information and decided that there was no statutory basis for requiring that these projections be met. The Agency has therefore deleted this requirement as being unnecessary and burdensome on the regulated community.

(ii) Most stringent federally enforceable emissions limitation. Several commenters objected to the fact that EPA was requiring the most stringent federally enforceable emissions limitations to be annualized (in accordance with a formula used in the NADB) and provided on the permit application. Commenters claimed that this was an inappropriate use of annualization factors.

Response: The Agency has reconsidered this information requirement and determined that it is not necessary. While under the proposal the information was necessary for substitution plans and Phase I extensions plans, the Agency has decided not to use the information in the case of substitution plans and has limited its use in Phase I extension plans. The reasons for the changes are discussed in the preamble sections of these plans. There is no need to require this information for all units. Further, while holding allowances under the Acid Rain Program does not exempt a unit from the requirement to comply with any other applicable limitation under the Act, the Agency believes that the Acid Rain permit application is not the appropriate place to record other limitations. Operating permits issued under title V will address the requirements of other programs.

(iii) Monitoring information. The Agency received several comments on the proposed requirement to submit certain monitoring information with the permit application, including the monitoring plan and the monitoring certification. Some commenters supported this provision, arguing for concurrent review of the application and the monitoring plan. Others argued that no formal approval of the monitoring plan should be required and that the timing of submitting monitoring plans nine months before monitor certification is due would be burdensome on sources.

One commenter was also concerned that if monitoring plans and monitor certifications became part of the permit, the permit would need frequent revisions as changes to the monitoring plan were made and as monitoring recertification became necessary. Instead, the commenter recommended that EPA allow the source to certify that it will comply with the monitor certification requirements in part 75.

Response: In the final rules, the Agency is not requiring that any monitoring information be submitted with the permit application. This decision is motivated principally by the timing of the permit application and monitoring requirements. In Phase I, permit applications are due February 15, 1993 (see section 408(c) of the Act), while monitors need not be certified until November 15, 1993 (section 412(b)). The Agency believes that it would be unnecessarily burdensome on sources to require monitoring submissions to be made so long before monitor certification is required. The timing problem is reversed in Phase II, where monitors must be certified by January 1, 1995 (section 412(c)) but permit applications are not due until January 1, 1996 (section 408(d)(2)). For the same reasons, the Agency has also deleted the requirement that monitoring plans and monitor certifications be a part of the permit. Instead, each Acid Rain permit will contain a standard requirement that the source must comply with part 75 (see § 72.9(b)(1)). Thus, a violation of any requirement in part 75 will be a violation of the permit (see the portion of the preamble for part 75).

(c) Conditional approval of compliance plans. (i) Enforceable milestones. Section 72.40(c) (proposed § 72.32(g)) allows sources to obtain conditional approval for compliance options. Thus, when the source submits its application, it may submit one or more compliance options for conditional approval. These compliance options will go through public notice and comment with the proposed permit. They will be approved conditionally, and the source may activate the options

by notifying the Agency. The activation of a conditionally approved compliance option is an administrative amendment.

One commenter objected that the provision that compliance options are not effective until activated by the designated representative could be used to evade the Act's requirement for enforceable compliance schedules for sources that employ certain optional methods of compliance. The commenter stated that a source that intended to rely on an optional method of compliance could identify the proposed method as conditionally approved and thereby prevent enforcement of interim milestones in its approved compliance schedule for that option by failing to activate the option until after the milestones have passed.

Response: The Agency believes that such a situation is not likely to occur. However, the Agency does not want to allow conditional approval to be used as a vehicle to escape from otherwise enforceable requirements. The Agency therefore has included a provision in the final rule that states that compliance options with enforceable interim milestones must be activated prior to the interim steps set forth in the compliance option or else not activated at all.

(ii) Notification of activation. Another commenter stated that EPA should not require notification of activation of a conditionally approved compliance option since the option has already been reviewed and approved by the Agency.

Response: The Agency disagrees. EPA needs notification of activation of the conditionally approved compliance option in order to modify the allowance allocations based on the compliance option. For example, the source may have a conditionally approved substitution plan; upon activation, the Phase II substitution unit becomes a Phase I unit eligible for allowances. Unless EPA receives notice, it cannot allocate allowances to the unit. In fact, because of the need to amend the unit's permit and allocate allowances, the final rule clarifies that conditionally approved substitution or reduced utilization plans must be activated no later than 60 days before the allowance transfer deadline applicable to the year in which the plan is to take effect. However, the notice does not give the Agency the opportunity to revisit the merits of the previously approved compliance option.

The need for notification is amplified where the conditionally approved compliance option involves two or more units that have different designated representatives. Under such circumstances, the compliance option cannot be implemented unless all the designated representatives agree to the activation. The prior notification requirement ensures that all the designated representatives will be aware of, and act in accordance with, the activation. Moreover, the final rule clarifies that all designated representatives of units involved in the compliance option must sign the activation notice.

(d) Interaction between permit and compliance plan. In the proposal, EPA asked for comment on whether compliance plans should be included in the permit (and possibly renamed "alternative operating scenarios") or should remain separate documents that are incorporated in the permit by reference to the compliance plan. There was no consensus among the commenters who addressed this issue, and none addressed the renaming issue. All of the commenters, however, were concerned with ensuring that sources have the maximum flexibility possible to make minor operational changes without being subject to a time consuming permit revision procedure.

Response: On reconsideration, the Agency believes that there is no practical or legal difference between including the compliance plan in the permit and treating the compliance plan as a separate document incorporated by reference in the permit. The Agency is adopting the approach of treating the compliance plan as part of the permit in order to make it clear that the plan, like the other permit provisions, is binding. Since the Act uses the term "compliance plan" and no commenters expressed any interest in changing the term used in the regulations, the final rule continues to use the statutory term.

(e) Permit shield. The permit shield provisions in proposed § 72.53(b) were supported by some commenters and opposed by others. Supporters stated that the permit shield would provide affected sources with certainty that compliance with the terms of the permit would shield the source from enforcement action. Opponents objected that the proposed shield was too narrow because the shield would not apply unless the permit conditions were clearly in compliance with title IV and the Acid Rain Program.

Response: EPA has retained in its final rule language similar to that in the proposed permit shield. The language in the proposal and in the final rule is very similar to the language in section 408(h)(2) of the Act, which provides that compliance with a permit issued under title V *which complies with this title* for sources subject to this title shall be deemed in compliance with the requirement to operate in compliance with an operating permit.

However, the Agency modified the language in the permit shield to clarify it and make it consistent with provisions, originally in the proposal and retained in the final rule, concerning the liability of the owners and operators of units involved in multi-unit compliance options or units with a common stack. Under these provisions, the owners and operators of one such unit are liable for violations of the plan by the other units. The permit shield in the final rule specifically refers to these provisions in order to clarify that such owners and operators continue to bear such potential liability. As discussed above, EPA's enforcement efforts will focus on the truly culpable parties.

(9) Federal Permit Issuance Procedures (Subpart F)

Under section 408 of the Act, EPA is the permitting authority in Phase I and, for geographic areas not covered by an approved State operating permit program, in Phase II. As the permitting authority, EPA is responsible for review of permit applications and issuance of permits. Section 408 requires EPA to develop regulations to establish permit issuance procedures.

(a) Denial of permit application. The Agency deleted proposed § 72.61(c)–(e) although these provisions do not appear elsewhere in the rules. These provisions concerned the denial of Acid Rain permit applications and Acid Rain permits and the procedure for correcting denied applications.

Response: The Agency believes that these sections are unnecessary and merely add confusion to the permit issuance process. The proposed and final rules already provide that if an application is incomplete, the Agency will issue a notice of incompleteness. Further, under these rules, the Agency may request supplemental information even where the application is complete. Moreover, where the permit application fails to meet the requirements of the Act, the Agency may issue a draft permit (called a "proposed" permit in the proposal) that disapproves compliance options requested in the permit application or may deny a draft permit. The Agency will provide a statement of basis explaining its action. In all of these circumstances, the designated representative may make necessary changes to the permit application. Thus, the Agency deleted the provisions in the proposal addressing denial and correction of permit applications and denial of permits because the provisions

duplicated, and to some extent contradicted, procedures already provided in the rule.

(b) EPA approval/denial time frame. One commenter objected to proposed § 72.70(b)(3), which stated that even though an application was deemed complete, the 6-month period for EPA action on the application would not begin to run where the designated representative subsequently failed to submit any requested supplemental information in a timely manner. The commenter stated that this provision is inconsistent with section 408(c)(2) of the statute, which requires EPA to act on compliance plans within 6 months and with proposed § 72.72(b)(2)(ii), which states that failure to provide supplemental information shall result in a denial of the permit.

Response: The Agency agrees that proposed § 72.72(b)(3) was inconsistent with the Act and has therefore deleted the provision. Under the final rules, where an applicant fails to submit supplemental information in a timely manner, the portion of the permit for which the information was necessary may be denied.

(c) Criteria for completeness. Several commenters requested that EPA clearly state the criteria it will use to determine whether a permit application is complete.

Response: The Agency reviewed proposed § 72.72(b)(3), which simply repeated or cross-referenced the requirements for permit applications. In the interests of clarity, the Agency has deleted this section and amended § 72.31 to set forth the information required in a "complete"permit application. The Agency believes that the information requirements set forth at § 72.31 are clear and straightforward and that sources will not have difficulty understanding and complying with the requirement to submit a complete application. In addition, the Agency will publish standard application forms that the sources can use. These forms, if filled out completely, will help ensure that the source submits a complete application.

(d) Proposed permits binding on a source. One commenter objected to proposed § 72.73(e), which makes proposed permits (called "draft" permits in the final rule to be consistent with the part 70 regulations under title V) binding on the source until a final permitting decision is issued. The commenter argued that "it would be extraordinarily unfair to impose on any source the terms of a mere proposed permitting decision that has not been subjected to proper procedures to ensure consistency with the Act." The commenter also stated that there is no statutory support for making the proposed permit binding on the source.

Response: The Agency agrees. Upon reconsideration of this issue, the Agency believes that a draft permit (formerly called a "proposed permit") should not be binding on the source since such a permit has not yet gone through notice and comment procedures giving the applicant and other parties the opportunity to address its consistency with the Act and with Agency policy. The Agency, therefore, has eliminated the requirement that the draft permit be binding on the source in lieu of a permit until the permit is issued. Instead, a complete permit application and compliance plan will be binding on the source until a permit is issued, as provided in section 408(c)(1)(A) and (d)(3) of the Act.

(e) Public comment period. (i) Permits and monitoring plan. EPA received several comments on the public comment provisions of its proposal. Several commenters supported the public comment provisions as proposed, but recommended that EPA allow comments on monitoring plans during permit review to minimize the possibility of redundant public comment periods.

Response: The Agency agrees that redundant public comment periods are a waste of time and resources for the Agency, the public, and the affected source. However, as discussed above, the final rules eliminate the requirement for a monitoring plan as part of the permit because of timing differences between permitting and monitor certification. Thus, in general, there will be no reason to make comment on the monitoring plan in the context of permit review.

(ii) Need for public comment. One commenter suggested that EPA eliminate the requirement for a public comment period for Acid Rain permits. The commenter states that utilities will either purchase allowances, add controls, or switch fuels and that since the Act gives sources the choice of which option to pursue, there is no need for public comment.

Response: The Agency disagrees. Section 408(a) of the statute mandates that title IV be implemented by permits issued in accordance with title V, as modified by title IV. A fundamental requirement of title V (set forth in section 502(b)(6)) is provision of an opportunity for the public to comment on the proposed permit. Furthermore, title IV gives sources the opportunity to request certain optional methods of compliance, such as substitution, Phase I extension, repowering extension, and reduced utilization plans. Before the Agency approves these optional methods of compliance, the public should have an opportunity to comment on the source's proposal and whether it meets the requirements of the Act. In addition, the comment period gives the source an opportunity to object to the draft permit that EPA proposes to issue in final.

(f) Fast-track modifications. (i) General. The Agency received numerous comments supporting the fast-track modification approach. Commenters supported promulgating Option 1, Option 2, or both. Several of the commenters who supported both options, however, stated that if EPA were to promulgate only one, it should promulgate Option 2. Several commenters who supported Option 1 also requested clarification from EPA on what it meant by "significant objections" to a fast-track modification that would require the source to shift to the regular modification procedure. The Agency received comments from environmental groups stating that they need at least 30 days to comment adequately on permit conditions.

Response: The Agency considered all of these comments and determined that Option 2 best addresses the concerns of the commenters. Option 1 provides only 15 days for public comment while Option 2 provides 30 days. The Agency believes that it is critical that interested persons be given an opportunity to comment adequately on significant changes in permit conditions. Option 1 does not allow adequate opportunity for comment. In addition, the Agency believes that proposed Option 1 could prove to be less expeditious than Option 2. Option 1 requires that the permit modification procedures be followed if significant objections are received during the 15-day comment period. Thus, to effect the change, two different permit revision procedures might have to be implemented. Under Option 2, there is a 30-day opportunity for comment. The Agency then has 30 days to review and act on the application and all comments. In many cases, Option 2 will prove to be more expeditious. For these reasons, the Agency has decided to promulgate only Option 2 in its final rule and clarify that fast-track procedures may be used, for any of the listed revisions, at the option of the designated representative submitting the permit revision.

(ii) Notice to interested persons. Numerous commenters also stated that, as proposed, only people who commented on the proposed permit would receive written notice of a fast-track modification. These commenters

objected to this limitation, stating that any person who asked to be put on a mailing list should receive notice of any fast-track modifications. One commenter pointed out that this limitation was inconsistent with proposed § 72.77 (public comments), which allows interested persons to put their names on a mailing list at any time and to receive notice of future actions affecting that permit.

Response: The Agency agrees with these commenters and has clarified in the final rule that written notice must be given to any interested person. Under § 72.2, an interested person is someone who either comments on the draft permit, testifies at a public hearing on a draft permit, or requests to have his or her name put on a mailing list to receive notice of any future actions on that permit.

(g) Minor permit modifications. In the proposal, the Agency asked for comment on whether some of the changes to the permit that were proposed as modifications or fast-track modifications could be accomplished using the minor permit modification (originally referred to as "minor permit amendment") procedure proposed in part 70 of this chapter. The Agency received several comments on this issue. One commenter agreed with EPA that the fast-track modification will be expeditious enough for approval of a new compliance option. Several other commenters stated that permit revisions should not be required for replacement of equipment but implied that if a revision were required, the minor permit modification would be appropriate.

Response: The Agency is not requiring notification or a permit revision for changes to equipment. In fact, permits will not include detailed information about how the source is going to operate or comply unless the source applies for an optional method of compliance. For example, if a source initially chooses to comply by switching to low sulfur coal but decides in 1997 to install a scrubber, neither the initial compliance decision nor the change will be included in the permit. This is because these approaches do not require approval of an option compliance method but rather require only that the source undertake to hold sufficient allowances to cover its emissions. Thus, the minor permit modification procedure is not needed for these types of changes. Moreover, since no commenters recommended that changes now covered by fast-track modifications be accomplished using the minor permit modification procedure, the Agency has decided not to promulgate a minor permit modification for changes to Acid Rain permits. The Agency believes that this revision procedure is unnecessary for the Acid Rain Program because the program requires notification only of changes in compliance options and of certain relatively minor permit changes, which can be accomplished through fast-track modifications and administrative amendments respectively.

(h) Administrative amendments. Generally, commenters supported the Agency's proposed administrative permit amendment provisions. These commenters believed that the changes included in this section could be accomplished without public notice and comment.

Response: The Agency agrees and has eliminated the requirement in the proposed rule that notice be given to interested persons of every administrative amendment to the permit. The Agency believes that interested persons should have access to current information about changes in permits and permit conditions. However, the Agency does not believe that the burden of providing notice is justified in this case because administrative permit amendments are relatively minor or noncontroversial and become effective without any opportunity for public comment. One example of such an administrative amendment is the adoption of or a change in a reduced utilization plan that does not involve designation of a compensating unit (e.g., a plan relying on energy conservation or sulfur-free generation). The Agency notes that the permits will be publicly available at EPA Headquarters and the Regional Office in the region where the source is located. In Phase II, permits will also be available at the office of the State permitting authority.

(10) State Permit Program Approval Criteria (Subpart G)

Under section 408(d) of the Act, each State must submit, for EPA's approval, a permit program, in accordance with title V, under which the State will issue Acid Rain permits for Phase II. The permit program must meet certain criteria in order to be approved by EPA. If the State program is approved by July 1, 1996, EPA will cease issuing Phase II Acid Rain permits. Under title V, State permit programs must also meet criteria concerning, and provide for, issuance of operating permits implementing other requirements of the Act in addition to those under title IV. The permit programs must be submitted by November 15, 1993.

(a) Complexity of acid rain program requirements. Some commenters were concerned about the complexity of the proposed Acid Rain regulations and the effect that complexity would have on States' ability to develop their permit programs under title V by the statutory deadline of November 15, 1993. One commenter suggested that EPA review separately State submissions under title V and title IV and give States longer to develop and submit their title IV permit programs.

Response: EPA believes that adoption of the commenter's suggestion is not warranted at this time. Both section 408(a) and section 502(a) of the Act require that title IV be implemented through title V, as modified by title IV. Thus, the Acid Rain Program will be an integral part of a State's title V operating permit program. Furthermore, the Agency believes that State regulations needed to implement the Acid Rain Program will not be particularly complex since many of the more complex aspects of the program (e.g., allowance allocations) will be implemented by EPA. The Acid Rain portion of the title V operating permit will be considerably less complex than the portion implementing the State implementation plan (SIP) and other requirements of the Act.

(b) Interference with allowance market. The Agency received numerous comments on proposed § 72.202(a), which bars a State operating permit program from interfering with the allowance market. The majority of the commenters supported § 72.202(a) as proposed, saying that State interference with the allowance program would frustrate a crucial objective of title IV: The achievement of nationwide emissions reductions at the least cost to utilities. However, a significant minority of the commenters opposed this section, claiming that it would limit a State's ability to protect legitimate interests, such as limiting the total deposition within the State and protecting national parks and forests.

Response: The Agency has retained this provision in its final rules. The Agency believes that these restrictions on State action are necessary to ensure that a national allowance market has an opportunity to develop and that sources are allowed to comply with the Acid Rain Program in the most cost-effective manner possible. The Agency realizes that States have a legitimate interest in protecting ambient air quality and that they therefore may want to limit emissions by restricting allowance trading. Nonetheless, the Acid Rain Program is a national program designed to reduce substantially total national

loadings of acid deposition precursors. The national transfer of allowances was clearly contemplated by the drafters of the Act. Geographical limitations on allowance transfers were included in early Senate and House versions of the bill, but later rejected in favor of national transfers. Congress was aware that failure of a nation-wide allowance market would create significant problems for new power plants (particularly those constructed by independent power producers) that are not allocated allowances by EPA but must purchase enough to cover their emissions. Report of the Committee on Energy and Commerce, House Report No. 490, at 366–67 (1990). In fact, prior versions of the bill that became the Clean Air Act Amendments of 1990 divided the country into two regions and permitted allowance transfers only within those regions. That restriction was removed in the final bill. See, e.g., *id.* at 372. Moreover, the active trading of allowances will enable utilities to adopt the least-cost approach to achieve their required SO_2 emissions reductions. The allowance market would likely fail if State or local permitting authorities had the ability to restrict the transfer of allowances.

Furthermore, under the Act, States have authority to protect local air quality concerns through requiring compliance with the SIP and with applicable National Ambient Air Quality Standards, rather than through restrictions on allowance trading. Section 403(f) provides that compliance with the Acid Rain Program will not excuse compliance with other applicable Clean Air Act requirements. The Agency realizes that a SIP will not allow a State to influence compliance decisions of utilities in neighboring States, which may have less stringent emissions requirements in their SIPs, and that emissions may travel across State lines and affect air quality or acid deposition in other States. Nonetheless, States had limited authority to influence compliance decisions of sources in neighboring States prior to enactment of the 1990 Amendments to the Clean Air Act, and the Agency does not believe title IV was intended to expand such authority. If Congress had intended to expand States' authority in this regard, it would have expressly said so.

(c) EPA intervention in appeals. Section 72 .202(i)(3) of the proposed rule required that the Administrator be given authority to intervene as a matter of right in any State administrative or judicial permit appeals involving an Acid Rain permit provision. This provision was proposed in order to ensure national consistency in State interpretations of Acid Rain permit requirements. One commenter considered this provision too intrusive on the rights of States to administer a delegated title V program.

Response: The Agency agrees only in part. For the rest of the title V program, EPA's oversight role through review and possible veto of permits will suffice. However, national consistency is needed in the Acid Rain Program more than in the rest of the title V program in order to ensure that a national allowance market has an opportunity to develop. To ensure that States do not adopt inconsistent interpretations of Acid Rain provisions that would adversely affect the allowance market, the Agency must have the opportunity to participate in State proceedings affecting Acid Rain permits. When there is an administrative appeal of an Acid Rain portion of a title V permit, there is a chance for inconsistent interpretations of Acid Rain provisions. The Agency needs to be assured that it will have an opportunity, before such interpretations are adopted, to present its interpretation of the Acid Rain Program in any State administrative appeal of an Acid Rain permit. However, by intervening in the State administrative proceeding, EPA may participate as a party in any subsequent State judicial appeal. In the unlikely case that EPA has no involvement until the judicial appeal, the Agency believes the courts will likely permit its participation as an *amicus*. Thus, the final rule requires a right of intervention only in State administrative appeals.

(11) Compliance Certifications (Subpart I)

Proposed subpart K, renamed subpart I in the final rule, described the compliance certifications that the designated representative would need to submit for each affected unit.

These compliance certifications included: Quarterly reports concerning emissions data and quality assurance information and the unit's compliance status with regard to deadlines and increments of progress; and annual reports concerning the requirement to hold allowances not less than total annual emissions, to submit a reduced utilization plan and surrender allowances for underutilization of Phase I units, and to meet nitrogen oxides emissions limitations. In addition, there were a number of periodic certifications required under the various compliance options.

Simplification and Reduction of Burden

A number of commenters found the subpart to be confusing in general and claimed that there was a need to reduce the regulatory burden imposed by the certification requirements.

Response: The Agency has endeavored to simplify and clarify the certification requirements and reduce the regulatory burden, while recognizing that compliance certification plays an important role in the Acid Rain Program. First, the annual requirements that all units certify to their total tons of emissions for the year and the total number of allowances held in the unit's compliance subaccount as of the allowance transfer deadline have been deleted. The Agency will already get quarterly emissions data from the units and will keep track, on an ongoing basis, of the allowances in each unit's account. There is no need to require submissions duplicating this data.

Also removed are the requirements to file quarterly certifications of each unit's compliance status with regard to scheduled deadlines or increments of progress (proposed § 72.401), periodic certifications to change certain deadlines under specified compliance options or to give notice of the failure to meet certain deadlines and reporting or submission requirements (proposed § 72.403), and certifications of any nonscheduled event that affects compliance (proposed § 72.403).

Annual Compliance Certifications and Other Submissions

In contrast to the proposal, the final rule requires each unit to provide annual and quarterly compliance certifications limited to certain key aspects of the Acid Rain Program. The annual compliance certification report must include certifications concerning the requirements to meet Acid Rain emissions limitations, maintain an up-to-date monitoring plan, and monitor and account for all emissions. Any changes in the facts that form the basis for monitor certification or for using excepted or alternative monitoring methods must be certified. In addition, quarterly submissions of monitoring data are still required under 40 CFR part 75. These submissions must be accompanied by a certification that the data was obtained or derived as required under part 75. (See § 75.64(c)). These certification requirements are consistent with the certification requirements under part 70 of this chapter.

Finally, some reports related to specific compliance options are retained in the final rule. Submissions concerning reduced utilization and the surrender of allowances are required. (The comments addressing those submissions are addressed above in the portion of the preamble on reduced

utilization). Only those periodic reports that the Agency found to be necessary to administer Phase I extension plans and repowering extension plans are still required. Some new information for which a periodic report is no longer required still requires a permit revision (e.g., to change the date of commencement of operation of qualified Phase I technology). See § 72.83 (administrative permit amendment).

The Agency believes that reducing the number, and clarifying the information requirements, of reports and certifications in this way will reduce the regulatory burden while meeting the statutory compliance certification and reporting requirements of title V that are applicable to title IV. Section 504(c) of the Act and the part 70 regulations implementing title V require compliance certifications at least annually that contain statements of the methods of determining compliance, such as monitoring, recordkeeping, and reporting requirements and test methods. See 40 CFR 70.5(c)(a). However, under the Acid Rain Program, unlike other programs under the Act, the Agency already receives a large volume of highly reliable data on unit operation, emissions, and monitor calibration. Consequently, the scope of compliance certification needed under the Acid Rain Program is less than under other programs under the Act and can be limited to what is set forth in the final rule.

IV. Discussion of Changes to Part 73—Allowance System

There are three main structural changes to part 73. First, the definitions are being moved to part 72. All definitions for the Acid Rain Program will be in part 72. Second, in subpart D, § 73.52 Submission of Transfers was merged with § 73.50 Scope of Transfers. Finally, also in subpart D, § 73.55 Non-Recordation of Transfers was merged with § 73.53 Notification. In addition, §§ 73.3 (Definitions) and 73.4 (Deadlines), which were previously published with subpart E—"Auctions, Direct Sales, and Independent Power Producers Written Guarantee", on December 17, 1991, pages 65592–65607, are recodified at §§ 72.2 and 72.12, respectively. This recodification is being performed in order to locate all the definitions for the Acid Rain Program in one place, solely for the ease and convenience of the reader. In addition, the definitions that are being recodified were already subject to notice and comment under subpart E of this part. Any changes made to the definitions were made to reconcile all the provisions of the Acid Rain Program and are not for the most part substantive changes. To the extent that there are any substantive changes, these changes were made in response to public comment on the definitions under other proposed subparts of the Acid Rain Program rules (since in many cases the same definitions appeared in various different subparts of the rules). Thus, EPA finds that for all these reasons, additional public notice and comment on this recodification is impracticable, unnecessary, and contrary to the public interest, pursuant to 5 U.S.C. 553(b)(B), 42 U.S.C. 7607(d)(1).

This section of the preamble discusses the four issues that were of most interest to the public, a number of additional significant issues, and any changes made to the rule as a result of comments on these issues. The section also clarifies the procedure EPA will use to return proceeds from the auction and direct sale to each unit. Other issues and comments are addressed in the Response to Comments Document.

On July 7, 1992, EPA proposed the Phase I allowance allocations; Phase I Extension Reserve, and establishment of the Special Allowance Reserve (57 FR 29939). To facilitate trading and Phase I compliance planning, as well as the first auction of allowances from the Special Allowance Reserve, EPA is choosing to finalize the Phase I allocations and reserves today, rather than promulgate them with the rest of the Phase II allocation rules. Only one comments was received on the Phase I allocations, and EPA has modified the allocations for the Sunbury plant in response to that comment. Five comments were made regarding the calculation of the Phase I Extension Reserve. Four of the comments supported EPA's calculation methodology and one requested a modification. EPA has chosen to maintain its calculation methodology and discusses the requested method in the docket. No comments were received on the establishment of the Special Allowance Reserve for the Phase I period, so the proposed language has been adopted.

A. Allowance Transfer Deadline

The "allowance transfer deadline" is the last day on which allowance transfers may be submitted to EPA for recordation in a compliance subaccount for use in meeting a unit's SO_2 emissions limitation requirements for the year. EPA proposed to establish January 30 of the calendar year following the year for which compliance is being established as the "allowance transfer deadline."

EPA received a total of 122 comments on the issue of the allowance transfer deadline. The majority of commenters requested a 45-day (or February 14) allowance transfer deadline. A significant number of commenters supported at least the proposed January 30 deadline, a few commenters requested a 60-day (or March 1) deadline, and some commenters supported a December 31 deadline. Those supporting a December 31 allowance transfer deadline claim that an allowance transfer deadline after December 31 establishes a bad precedent for a market-based program. They believe that companies should be able to plan for the transfers needed for compliance well in advance of December 31, and thus should not need an extended deadline. They also believe that companies should maintain prudent contingency reserves to allow them to meet the requirements on December 31. In addition, the commenters are concerned that such an extension or "book closing period" is inconsistent with the intent of the Act and its enforcement and compliance provisions. Finally, they believe a January 30 deadline makes it difficult to complete the steps required for development of excess emission offset plans, due by March 1, on a timely basis.

Other commenters felt that the proposed 30-day, or January 30, transfer deadline is appropriate. They argue that 30 days are needed to provide units with sufficient time to transact and submit allowance transfers. They also comment that the January 30 deadline affords units one month from the submission of transfers to complete and submit excess emissions offset plans, if necessary, and EPA one month to record final transfers and resolve any associated errors.

The commenters supporting a 45-day, or February 14, allowance transfer deadline state that such a deadline is in line with Congress' intent and has no effect on the emission reduction goals of the program. In addition, they argue an extra 15 days will result in fewer transfer errors, and reduce the likelihood that any utility will actually be out of compliance and have to file an excess emission offset plan. Commenters supporting a longer transfer deadline also claim that EPA should not need 30 days after the transfer deadline for recording allowance transfers and handling claims of error, especially with an electronic Allowance Tracking System. They argue that additional time for compliance procedures is important for small utilities that do not have the staff or

expertise to promptly complete their compliance certification reports and locate allowances, if needed. A number of utilities commented that extending the transfer deadline by 15 days still leaves them enough time to prepare and submit their excess emission offset plan by the statutory deadline of March 1. Finally, they claim that allowing more time to negotiate allowance transactions for compliance helps minimize the overall compliance costs of the program.

A number of commenters favored a January 30 or February 14 allowance transfer deadline for its accommodation of utilities in power pools or those seeking to create allowance pools. For such power and allowance pools, they argue an extended allowance transfer deadline would enable member units to arrange for allowances to be transferred after the designated representatives have fully collected and assessed the final emissions data for the year on a system-wide or pool basis. At that point, since compliance is determined on a unit-by-unit basis rather than on an aggregate basis, surplus allowances from certain units could be transferred during the extended allowance transfer period to any units in the pool that needed them. These commenters assert that a December 31 transfer deadline, coinciding with the calendar year compliance requirements mandated by the Act, could inhibit the creation and operation of such power and allowance pools.

Several commenters suggest a 60-day, or March 1, allowance transfer deadline. They claim that such a deadline is in the interest of a viable and flexible emission trading system, and that it provides adequate time for the staffs of small utilities to comply with the complex rules.

Response: As stated in the preamble to the proposed rule, EPA believes the additional flexibility of an extended allowance transfer period is important to the Acid Rain program and is also consistent with Congressional intent.

The final rule, in § 73.35(a), sets January 30 as the date of the allowance transfer deadline. EPA continues to believe that a January 30 deadline provides units with ample time to transact and submit allowance transfers, and in the case of units with excess emissions, to submit offset plans within 60 days after the end of the year.

Through continuous emissions monitoring under part 75, units will be able to estimate their emissions during the year and determine their exact annual emissions within hours of year-end. This capability will allow allowance or power pools as well as individual units plenty of time to transact and transfer allowances before January 30.

A February 14 allowance transfer deadline would compress the amount of time for both EPA and the authorized account representatives to complete several time-consuming activities which must occur before March 1. First, EPA will have to record transfers and notify the authorized account representatives as to whether the trades are recorded. If a large volume of transfers are submitted at once, there may be a delay between submission and recordation for any given transfer. Second, the authorized account representatives will need to determine the accuracy of any recordations and, if necessary, to submit error claims to EPA. Finally, EPA will have to resolve each error claim. EPA believes that the period from February 15 to March 1 does not offer sufficient time to carry out these activities reliably, especially in Phase II of the Acid Rain program when the number of affected units will increase to over 2,000.

Extending the allowance transfer deadline to March 1, as several commenters suggested, would leave no time for these activities and is therefore not a viable option.

Because of all the activities that must take place between the January 30 allowance transfer deadline and the March 1 deadline for submission of excess emissions penalties and offset plans, EPA strongly encourages utilities to submit allowance transfers before the January 30 deadline. Designated representatives should try to submit compliance-related transfers prior to the allowance transfer deadline because if an error is made on the transfer form, there would still be time to resubmit the transfer before the January 30 deadline. Under the final rule, resubmission of the transfer after January 30 would be too late to use these allowances for compliance purposes in the previous calendar year. An additional incentive to submit transfers early is that it provides more time to file a claim of error regarding an allowance transfer and to have the claim resolved (see next section). Resolution of a claim of error could be of critical importance if the trade's outcome determined whether the unit was in compliance.

B. Serialization

In § 73.34(d) EPA proposed to assign a unique identification number to each allowance. Most commenters supported EPA's proposal because it provides a method for establishing a cost basis for allowances and, therefore, greater flexibility for tax and compliance planning purposes. A few commenters, however, disagreed with the need for serialization, except to indicate the compliance use date for each allowance. One commenter argued that the compliance use date was necessary to establish the cost basis for an allowance, but that the assignment of a unique number would destroy the fungibility of allowances. Another said that EPA's assignment of a unique number was unnecessary because a utility would probably assign its own unique numbers that are consistent with its internal accounting system. A third commenter argued that the administrative burden of assigning a unique identification number to each allowance outweighed any possible benefits. Still another commenter claimed that only an identifier of the year for which the allowances are valid and the attachment of a transaction number when allowances are transferred are necessary for tracking purposes.

One commenter recommended that, in addition to the compliance use date, an allowance's unique identification number include a means of identifying the source of the allowance's original allocation. This would enable utilities and their regulators to distinguish between allocated and acquired allowances for tax and accounting purposes.

Response: EPA continues to believe that the assignment of unique serial numbers to allowances will provide significant flexibility to the market's participants in their financial, tax, and compliance planning efforts. Furthermore, because such numbers would be useful to most companies for their internal recordkeeping purposes, EPA decided that the aggregate benefit of providing a standard numbering system outweighs the administrative cost to EPA of generating and tracking the identification numbers.

In response to the comments, EPA will assign a unique number to each allowance that will include the compliance use date and that will enable utilities to differentiate between allocated and purchased allowances. EPA is including the compliance use date as part of the unique number to further enhance the establishment of a cost basis for each allowance. EPA agrees that it will be useful to readily identify compliance dates and to distinguish allocated from acquired allowances using serial numbers since it is important to utilities and regulators for establishing a cost basis for allowances.

EPA is not providing, by regulation, the exact format of the serial numbers for the allowance system. In implementing the system, EPA will

limit the use of source codes to those cases where such identification is necessary.

C. Verification of Energy Savings

Section 404(f)(2)(B)(ii) of the Act requires an applicant to the Conservation and Renewable Energy Reserve (CRER) to quantify its estimates of avoided emissions according to regulations promulgated by the Administrator. EPA proposed to defer conservation verification to State regulators in cases where the State has regulatory oversight. EPA's rationale for this approach was that regulatory scrutiny for conservation savings applied for under the Reserve is likely to be fairly rigorous because utilities applying for the program must be subject under the Act to "net income neutrality" ratemaking structures. EPA also reasoned that with the complexity and multitude of verification methods for energy savings, verification guidelines must be flexible enough to allow States to develop procedures that best suit the circumstances of their utilities. In cases of non-State-regulated utilities, EPA proposed to require the use of an EPA Conservation Verification Protocol (CVP), to be published at a later date.

Some commenters questioned EPA's approach for deferring verification of energy savings to States. It was noted that some methods of net income neutrality rate-making do not link the revenues awarded to the utility with the amount of verified energy savings. For example, ratemaking structures that decouple a utility's revenues from sales volumes do not require verification of savings from conservation programs. Several commenters also noted that State verification methods vary widely in their accuracy and rigor. For example, some States base their verification of savings solely on engineering estimates, which may be grossly inaccurate.

Commenters gave a number of suggestions for revising the criteria for deferring conservation verification to States, including (1) requiring all applicants to the Reserve to use the CVP or some other verification standards that EPA would promulgate, which might include region-specific engineering estimates for conservation measures; (2) having EPA adopt State estimates of energy savings only in cases in which the State requires "measured" energy savings, i.e., savings that are verified in statistically valid studies using billing data or data collected by electricity end-use sub-meters; and (3) having EPA defer to States only if the State uses evaluation of energy savings to determine performance-based financial awards for energy conservation programs and these performance based awards are subject to adjustment to reflect periodic evaluation of energy savings.

Response: EPA has decided to adopt this last approach with one modification. Section 73.82(c) of today's rule allows States to perform verification of energy savings if they use evaluation of energy savings to determine *any* type of performance based rate adjustment, rather than just performance based *financial awards*, as suggested by the commenter. EPA believes that allowing this broader category of performance based mechanisms is more consistent with today's definition of net income neutrality, which allows both performance-based financial awards (i.e., "shared savings mechanisms") and "lost revenue adjustment mechanisms." For both of these types of mechanisms, regulators must evaluate energy savings achieved by utility conservation programs in order to determine the proper adjustment to a utility's rates necessary to recover lost revenues or to provide a financial award.

EPA has adopted this approach for several reasons. First, the Agency believes it is representative of EPA's original rationale of deferring to State regulators where verification is likely to be fairly rigorous. The Agency believes that there is an incentive for rigorous verification when evaluation of energy savings is used to determine how much of the ratepayer's money will go towards conservation incentives. In contrast, without this tie to performance based rate adjustments, States might have an incentive to overestimate savings to obtain the largest number of Reserve allowances.

Second, although the use of engineering estimates would still be allowed, the requirement to periodically modify performance-based rate adjustments through the evaluation of energy savings would help ensure that the State is committed to good evaluation practices. EPA notes that evaluation of energy savings is a new and rapidly evolving field and that States often begin their evaluation programs solely with engineering estimates. Most evaluation experts agree, however, that while engineering estimates are useful, they should be supplemented with a statistically valid measurement of the change in energy use resulting from installation of conservation measures.

Finally, EPA believes that this approach is more consistent with the fundamental approach of the Acid Rain program, which encourages flexibility but insists upon appropriate measurement standards. Thus, while today's regulations provide a minimum standard for deferring conservation verification to States, EPA is not prescribing verification methods or procedures. States will still have the flexibility to design their own verification approaches. Because of the diversity of evaluation methodologies and the ongoing evaluation activities of States, EPA believes that this approach will be more effective than mandating specific methods or requiring universal use of the CVP.

EPA also notes that it has modified the proposed verification requirement for applicants that do not qualify to have verification performed by their State commissions. The proposal required such applicants to use the CVP. The final rule requires applicants to demonstrate to the satisfaction of the Administrator that energy savings have been secured and allows applicants to do so through use of the CVP.

D. Appropriate Biomass Categories

EPA proposed to allow the biomass component of municipal solid waste (MSW) to be considered as biomass resources for purposes of the Reserve. The Agency noted in the proposal that inclusion of MSW was consistent with the definition of biomass in the Public Utility Regulatory Policies Act of 1978 (PURPA). EPA also proposed to limit the total number of allowances that may be allocated in connection with any one of the four categories of renewable resources—biomass, solar, geothermal, and wind—to no more than 10% of the Reserve, or 30,000 allowances. This reflected EPA's concern that biomass, which, in the aggregate, represents more than 90% of the combustible MSW stream, could absorb a disproportionate share of the Reserve.

Twenty-five commenters opposed EPA's proposal to allow the biomass components of MSW to be considered a biomass resource for purposes of the Reserve. One set of commenters stated that the goals of PURPA and the Clean Air Act are entirely different; PURPA was intended to stimulate energy production, while the Clean Air Act was designed to promote clean air. Moreover, these commenters argued the CRER was created to accelerate the development of conservation measures and renewable energy technologies that meet two standards: (1) They enhance the goals of the Act to improve air quality, and (2) they are in greatest need of an additional Federal incentive. The commenters argued that while incineration of MSW may be a suitable

method of solid waste disposal in some cases, it does not meet these two standards.

Fifteen additional commenters noted that MSW waste-to-energy projects are not environmentally benign or beneficial, and they emit a number of pollutants including SO_2, NO_x, particulates, and a variety of toxics. Commenters also contended that MSW waste-to-energy generation is a well developed technology that does not need additional incentives. Finally, several commenters argued that the additional incentive for incineration of MSW provided by Reserve allowances could disadvantage more environmentally beneficial solid waste disposal options such as source reduction and recycling.

Only one commenter unequivocally supported EPA's proposal to allow the biomass components of MSW to be considered a biomass resource for purposes of the Reserve. The commenter argued that all renewable technologies covered by PURPA should be considered qualified renewable energy technologies for purposes of the CRER.

One additional commenter argued that before receiving allowances from the CRER, waste-to-energy projects should obtain certification from the Department of Energy (DOE) that the project was operating in full compliance with an approved integrated solid waste management plan. The commenter stated that this plan should include recycling to the maximum extent practicable.

Response: EPA, having considered these comments, finds that there is no policy or statutory basis for excluding the biomass component of MSW as a biomass resource for purposes of the Reserve. While commenters are correct in noting that MSW waste-to-energy (WTE) projects emit a number of pollutants, EPA has already promulgated regulatory standards that mandate, reductions in these emissions to acceptable levels (*FR* Vol. 56, No. 28, February 11, 1991, p. 5488). Moreover, WTE plants often yield certain environmental benefits in addressing solid waste management concerns. In any event, the Act does not contemplate an environmental ranking of renewable energy technologies.

EPA agrees with the comment that WTE technology is both mature and geographically dispersed. The number of WTE projects has grown substantially in recent years—65 WTE projects began operation in the years between 1980 and 1989, and 75 additional projects are planned or have recently begun operations. However, the exclusion of a particular renewable technology from access to the Reserve merely because it is highly cost-effective would be totally inconsistent with the thrust of the emissions allowances system, which uses a flexible market-based system rather than a command-and-control approach precisely because the former can elicit the most cost-effective responses to meet environmental objectives and energy needs. Finally, Congress explicitly considered the definition of "qualified renewable energy" in the Act and, while explicitly excluding hydropower, did not exclude WTE biomass. Thus, on legal as well as policy grounds, it would be inappropriate for the Agency to impose such a restriction. Accordingly, after considering the comments received, the Agency has determined that MSW will remain on the list of qualified renewable energy technologies in Appendix (A)(3) of today's rule.

The proposed rule assured that no single technology would absorb a disproportionate share of the Reserve by limiting to 30,000 the amount of allowances that can be allocated from the Reserve. This same limitation is included in the final rule.

E. Other Changes to Part 73

(1) Allowance Accounts

In § 73.31(a) of the proposed rule, EPA specified that the allowance account for an existing affected unit would be established in the Allowance Tracking System no later than January 30, 1993. Accounts for new units would be established upon receipt of a valid certification of representation for a new unit pursuant to part 72.

Upon review, EPA is eliminating the specification that EPA establish Allowance Tracking System accounts by no later than January 30, 1993. Because EPA imposed this specification upon itself and it was not a statutory requirement, EPA believes its inclusion is unnecessary.

(2) Freezing of Accounts

In § 73.50(a)(4) EPA proposed to prohibit, or give the Administrator the discretion to prohibit, EPA from executing any transfers of allowances from a compliance subaccount if the unit had excess emissions in the previous calendar year and the Administrator had not yet deducted allowances or approved the unit's offset plan. In such cases, EPA would have allowed a transfer if the number of allowances in the compliance subaccount equaled or exceeded the sum of the number of allowances subject to the transfer and the unit's excess emissions in the previous year.

Several commenters questioned the purpose of giving EPA authority to "freeze" an affected unit's subaccounts in the ATS under these conditions. Specifically, they requested EPA to delete these proposed provisions (§ 73.50(a) and § 73.55(b)).

Response: On reexamining this issue, EPA has decided to delete these provisions and has revised the rule accordingly. EPA reasons that even if a unit's offset plan to cover its excess emissions in the previous year has not yet been approved and allowances have not yet been deducted for excess emissions, EPA should allow transfers of allowances out of the current year's compliance account. Once the offset plan is approved, EPA could deduct allowances from the current compliance subaccount as the plan requests. If a unit fails to abide by its offset requirements and lacks sufficient allowances in its current compliance subaccount to cover its excess emissions, EPA has the authority in accordance with § 77.4 to automatically deduct allowances from the current compliance subaccount whenever more allowances are recorded in the compliance subaccount. The only situation in which allowances would be unavailable to EPA would be if the unit transferred all allowances from its account and ceased operation, which could be done before an offset plan is even submitted to EPA. In such a case, EPA could pursue enforcement actions. Therefore, EPA agrees that the proposed provisions concerning freezing an affected unit's subaccount are duplicative and unnecessary.

The final rule contains language under the general requirements of part 72, subpart A that allows EPA to take action to protect the orderly and competitive functioning of the allowance system. This is to ensure that EPA is able to protect the allowance system and participants from fraud or misrepresentation.

(3) Account Error and Dispute Resolution

As proposed in § 73.37, EPA required that all claims of error be submitted within 20 business days following the date of submission of the recordation notice or within 10 business days of the date of EPA's notification of the recordation. Only one additional appeal to the Administrator's decision of the submitted claim would be considered. No appeals provision was made for EPA's corrections and the Administrator's discretion to waive deadlines.

Commenters requested that such appeals procedures be extended to

apply also to corrections made at EPA's own discretion and the Administrator's right to waive deadlines. Other commenters supported having a more formal administrative appeals procedure, similar to the one proposed in part 72, to cover any action by the Administrator under part 73.

Response: EPA reviewed its proposed claim of error procedures to ensure that adequate response time for account holders is provided consistently throughout the compliance period. EPA is modifying the claim of error process so that only properly documented claims submitted within 15 business days following the date mark of notification of the transfer's recordation will be considered, subject to the waiver of deadlines process § 73.37.

As defined in § 73.37, a properly submitted claim consists of (1) a description and complete documentation of an error allegedly made by EPA, (2) a proposed correction, and (3) certification by the authorized account representative. Any appeal of the decision made by the Administrator in response to the submitted claim of error will be handled through the administrative appeals procedure contained in part 78. The deadline and process will not be altered for claims submitted near or after the Allowance Transfer Deadline. This means that unless EPA uses its discretion to waive the deadlines, EPA would have 20 business days to respond in writing to a claim of error received on the allowance transfer deadline. Thus, the designated representative might not know the outcome of the claim until after March 1. This could present a problem to the designated representative where the outcome of this claim of error is of critical importance in determining whether the unit was in compliance. However, if EPA made an error in recordation that appeared to put the unit out of compliance, EPA will correct the error and acknowledge that the unit was in compliance.

Based on supporting comments received, EPA is extending the claim of error process to cover EPA corrections, and the administrative appeals process described in part 78 will extend to appeals of the Administrator's discretion to waive deadlines contained in § 73.37(f).

In addition to the claim of error process for allowance transfers, the administrative appeals procedure in part 78 can be applied to any decision or action by the Administrator under part 73.

(4) Authorized Account Representative Notification of Submissions

In part 72, EPA proposed that the designated representative provide each owner and operator with a copy of any Acid Rain program submission. EPA did not propose in part 73 that the authorized account representative notify all persons who have an ownership interest in the account of any Acid Rain Program submissions. This meant that non-unit account holders may be unaware of submissions made by their authorized account representative.

One commenter suggested that where the designated representative is engaging in a transfer that violates the binding agreement to represent the owners, EPA should temporarily halt the transfer for a period of time sufficient to obtain a temporary injunction pending resolution of the conflict.

Response: Under part 72 the designated representative is required to notify all owners and operators of any Acid Rain program submissions. In addition, § 73.33(b) of the final rule requires the authorized account representative to notify all persons who have an ownership interest with respect to the allowances held in the account of any part 73 or part 78 Acid Rain Program submissions by the date of the submission.

EPA is requiring such notification for all account holders for two reasons. First, where a transfer violates the binding agreement, requiring the notification will give an owner or a person with an ownership interest at least the period of time that it takes EPA to process and record the transfer to obtain a temporary injunction from a court. Second, because in some cases utilities will set up non-unit accounts to pool allowances, EPA believes this notification requirement is necessary to ensure that the owners and operators of the units in the allowance pool are notified. EPA is limiting this notification requirement to part 73 and part 78 submissions because the other parts are not relevant to non-unit accounts.

(5) Allowance Deductions for Units Sharing a Common Stack

In § 73.35(f) of the proposed rule, EPA planned to aggregate the allowances in the compliance subaccounts for all units governed by a common stack plan for purposes of deducting allowances to meet SO_2 emissions limitation requirements. Following the deductions, EPA would return any remaining aggregated allowances to each unit's account on a per capita basis.

EPA received one comment supporting the proposal. However, the commenter noted that the importance of this aggregation will be less if EPA proceeds with its non-unit account proposal.

Response: EPA reviewed and decided to modify the manner in which allowances are deducted for units sharing a common stack. Instead of aggregating allowances, § 73.35(e) of the final rule allows the designated representative to identify the percentage of allowances to be deducted from each unit's compliance subaccount. In the absence of such an identification, EPA will deduct an equal percentage from each unit's compliance subaccount. Of course, the designated representative still has the option to identify, by serial number, the specific allowances to be deducted. These specific allowances would be deducted first; then, if more allowances need to be deducted, the percentage would be applied.

EPA is making this change to conform to the unit-by-unit allocation and compliance provisions of the Act and the Acid Rain program. By aggregating the allowances as in the proposal, if one unit is in violation for excess emissions, then all are. However, this rule enables compliance and excess emissions violations to be determined on a unit-by-unit basis by applying a percentage for allowances to be deducted from each unit's compliance subaccount. Also, since EPA is proceeding with the non-unit account proposal, EPA agrees with the commenter that aggregating allowances is less important.

(6) Transfer Recordation—Non-recordation of Transfers

Four commenters requested EPA consider the date of recordation of a transfer to be the date it was originally received by EPA. They also requested that any subsequent claim procedures to correct the recordation of a transfer not affect the original date of recordation, which would be the original date of its receipt by EPA.

Response: Although EPA understands the commenters' concern that the original date of submission be acknowledged, EPA does not believe the date of recordation will have substantial impact on the effectiveness of any transfer agreements. The buyer and seller can arrange the date their agreement takes effect for legal purposes separately from the actual date of transfer of allowances by EPA. Therefore, EPA has not changed the rule, and the date of recordation will be the date EPA enters the information into the Allowance Tracking System. Any incomplete or inaccurate transfer forms

will be returned to the senders and will not be recorded. Resubmitted transfers will be treated as if they are a new transfer and the date of recordation will be the date EPA enters the information into the ATS. The original date of submission is not considered to be the date of recordation because resubmitted transfers are considered to be new transfers.

(7) Collection of Market Information

EPA proposed not to collect price and other terms of allowance transactions, and the rule is not changed from the proposal, despite some comments expressing concern on this issue.

Response: While EPA is not collecting information on price and other terms of allowance transfers, EPA is providing some market information by publishing the results of the annual auction and sale and by making the information contained in each allowance account available, in summary form, for public review. EPA recognizes that there are concerns about the availability of market information on allowances. EPA continues to believe that market information on allowances will be available through other public and private channels such as the Federal Energy Regulatory Commission (FERC) and futures exchanges. However, to address these concerns EPA will evaluate the allowance market and the availability of market information prior to Phase II to determine what action, if any, may be needed.

(8) Least Cost Planning

(a) Section 404(f)(2)(B)(iii)(II) of the Act requires qualified energy conservation measures or qualified renewable energy generation to be consistent with the applicant's least cost plan. Although this requirement was included in § 73.82(a)(5) of the proposal, it was inadvertently omitted from § 73.81(c)(2) of the proposal, which listed the requirements for approval of qualified renewable energy technologies not already listed in Appendix (B)(1) of the rule. Section 73.81(c)(2)(i) of today's rule has been corrected to include this requirement.

(b) One commenter questioned the relevance of the proposed rule's least cost planning requirement for independent power producers (IPPs) that make use of renewable energy. Generally, these units sell wholesale power to other utilities and are not subject to least cost planning requirements. The commenter suggested that it would be more meaningful to require these types of applicants to demonstrate that the renewable energy generation was *purchased* pursuant to the *purchasing* utility's least cost plan, which should be approved or accepted by the appropriate regulatory authority.

Response: EPA agrees with the commenter and has adopted the suggested change in § 73.82(a)(8). The Agency believes that this approach is more consistent with the actual operation of IPPs and with the intent of the Act.

(c) EPA proposed that if an applicant to the Reserve is not subject to the ratemaking jurisdiction of a State regulatory authority, its least cost plan must be approved and certified by the entity with rate-making authority for the applicant. The Agency also proposed that applicants not subject to the rate-making jurisdiction of an entity with ratemaking authority must apply to the Administrator for approval of the plan. Five commenters suggested that the rule language be clarified to specify that public power utilities not subject to State ratemaking authority have their plans approved by the appropriate local ratemaking authorities. In addition, several commenters noted that *all* utilities are subject to the rate-making jurisdiction of an entity with rate-making authority. These commenters suggested that EPA clarify that a least cost plan could be approved by any entity with rate-making authority.

Response: EPA agrees with the commenters' suggestion and has revised language in § 73.82(a)(6) and § 73.82(a)(7) of the final regulations to clarify that the least cost plan may be approved by any entity that regulates the rates of the applicant.

(d) EPA also received comments urging the Agency to revise the proposed rule so that the definition of an "approved" least cost energy plan includes least cost plans that are "accepted" by the State regulatory authority. The commenters suggest the change because some State regulatory authorities are unwilling to approve a utility's least cost plan out of concern that such approval will tie the hands of future State regulatory bodies. However, these State authorities will *accept* a least cost plan if it complies with the State regulatory authority's requirements.

One commenter also suggested that where States implement ratemaking and planning processes that are consistent with least cost planning principles, they should not need to have a formal "plan."

Response: The final rule contains two changes regarding the requirements for regulatory oversight of a utility's least cost plan. The first, in § 73.82(a)(6) and § 73.82(a)(7), would allow a commission to "accept" a least cost plan in addition to "approving" a least cost plan. The second change, in § 73.82(a)(4), would allow a utility to meet the least cost planning requirement if it has a least cost plan *or* a "least cost planning process."

(e) One commenter questioned EPA's requirement that least cost plans be subject to public notice and comment. The commenter stated that EPA should allow States to use alternative public participation procedures such as collaborative processes that allow public participation from interested groups.

Response: Section 73.82(a)(4) of the rule has been revised to require public notice and comment on a least cost plan *or* a comparable public participation process.

(9) Net Income Neutrality

EPA received comments on several issues related to the net income neutrality provision. The Agency has addressed these comments in consultation with the Department of Energy (DOE), which is responsible for certifying that an applicant's State regulatory authority has implemented provisions that meet net income neutrality requirements.

(a) Six commenters stated that the definition of and the requirements for net income neutrality should state explicitly that they only apply to investor-owned utilities (IOU). The commenters noted that public power utilities are non-profit and do not have "net income."

Response: EPA and DOE agree with the commenters and have added language to § 73.82(a)(9) of today's regulations that specifies that this requirement only applies to IOUs.

(b) One commenter argued that the three compliance approaches for net income neutrality specified in § 73.82(a)(9) do not, in and of themselves, constitute net income neutrality.

Response: EPA and DOE believe that the mere existence of one of these three mechanisms does not necessarily meet the net income neutrality requirement and that the specifics of each rate-making mechanism must be reviewed by the Secretary of Energy before a determination of net income neutrality can be made. Accordingly, § 73.82(a)(9)(ii) of today's regulations clarify this point.

(c) Three commenters stated that the proposal's definition of net income neutrality implies that utilities must use a "rate basing" accounting mechanism for recovering the costs of conservation programs. The commenters contend that the term "net income on book value"

used in the definition suggests that conservation expenditures must be treated as a capital expense that should be included in the utility's ratebase. These commenters noted that many utilities use an "expensing" mechanism to recover conservation expenditures, a mechanism that does not add to utility book value.

Response: It was not the intent of the proposal to prescribe the type of cost recovery mechanisms that may be used for conservation expenditures. EPA and DOE believe that the choice of cost recovery mechanisms should be left to the discretion of utilities and their economic regulators. Therefore, the term "book value" has been deleted from the definition of net income neutrality in § 72.2 of today's regulations.

(d) Five commenters argued that the definition of net income neutrality should not imply that ratemaking procedures should *guarantee* that utility incomes will be no lower if investments in conservation are made. Rather, ratemaking procedures should provide the *opportunity* for utilities to earn a net income comparable to that which it would have achieved without the conservation programs. The commenters noted that under some shared savings incentive mechanisms the return received by some utilities depends upon the verified performance of their conservation investments.

Response: EPA and DOE agree that providing an opportunity for net income neutrality is consistent with the intent of the net income neutrality requirement. These regulations modify the definition of net income neutrality in § 72.2 to include State ratemaking approaches that provide for this opportunity based on performance-based results of conservation programs.

(10) Qualified Conservation Measures

(a) Three commenters stated that EPA should clarify or delete the requirement that there be no net increase in sulfur dioxide from qualified conservation measures. For example, one commenter noted the difficulty of determining the exact type and amount of fuel that might be avoided by the marginal energy savings of a particular conservation measure.

Response: EPA notes that it was not the intent of the proposed regulations to require such a detailed evaluation of the emissions impacts of given conservation measures. Rather, the requirement was directed towards measures that increase energy efficiency by utilizing industrial waste gases containing sulfur. EPA believes that where utilization of these waste gases does not lead to a net increase in sulfur dioxide (i.e., cases where the gas is already being flared), these measures should be considered qualified energy conservation measures. The Agency has modified language in § 73.81(a) and § 73.81(b) of the regulations to better reflect the intent of this provision.

(b) EPA received a comment that supported EPA's criteria for approving qualifying DSM measures not explicitly listed in the appendix to the regulations. However, the commenter explained that requiring specific approval of qualified conservation measures by the applicable State regulatory authority or by the Administrator may stifle flexibility to install innovative measures.

Response: The final rule, therefore, states in § 73.81(a)(2) that EPA will deem as qualified each conservation measure installed pursuant to a conservation *program* and approved by the relevant authority, as long as it meets the criteria listed in § 73.81(a) and is not an excluded measure under § 73.81(b).

(11) Applicability for CRER

(a) EPA proposed that an applicant would be eligible to apply to the Reserve if "any subsidiary of the applicant" owns or operates an affected unit. One commenter argued that eligibility should also extend to any subsidiary of the applicant's *holding company* that owns or operates an affected unit, either in whole or in part.

Response: EPA agrees that this change reflects the language and intent of the Act, and § 73.82(a)(2) of today's regulations reflect this change.

(b) EPA also proposed that an applicant would be eligible to apply for the CRER if it is a utility or an industrial customer that purchases power from an affected unit under a "life-of-the-unit" firm power contract.

Response: The Agency now believes, however, that it would be contrary to the intent of the Act to allow industrial customers that purchase power from affected units to qualify for the Reserve. Section 404(f)(2)(A) clearly requires that an applicant to the Reserve be an "electric utility", which is defined in section 404(f)(1)(C) as any person, State agency, or Federal agency, which sells electric energy. Since industrial customers with a life-of-the-unit contract *buy* electricity, rather than *sell* electricity, they would generally not meet the definition of an electric utility. Consequently, § 73.82(a)(2) of these regulations deletes industrial customers from the language describing the types of eligible applicants to the Reserve.

(12) Application Requirements

(a) EPA proposed that applicants to the Reserve must pay in whole or in part for qualified conservation measures or qualified renewable energy generation, either directly or through payment to another person. The Agency also proposed that the applicant must specify the amount spent on the conservation measure or renewable energy generation. One commenter argued that in the case of renewable energy generation produced by independent power producers, these expenditures are proprietary information that should not be disclosed.

Response: EPA now believes that information on expenditures of both renewable energy generation and qualified conservation measures are unnecessary. Rather, EPA will require in § 73.82(a)(3) that applicants to the Reserve certify that they have paid for the qualified conservation measures or qualified renewable energy generation.

(b) EPA proposed to allocate allowances from the Reserve for qualified renewable energy generation purchased or generated by an applicant. One commenter stated that EPA should allocate allowances for qualified renewable energy generation only to utilities purchasing such generation, rather than to the generating utilities. The commenter argued that such a policy would provide the strongest incentive for the development of renewable energy.

Response: EPA believes that the commenter's suggestion would be contrary to section 404(f)(2)(F) of the Act, which clearly provides for allocation of Reserve allowances to *both* purchasers and generators of qualified renewable energy generation. However, EPA has added language to § 73.84(g) of these regulations that would prevent the generator and the purchaser of the same renewable energy generation from receiving allowances from the Reserve based on the same kilowatthours of electricity generation and the same avoided emissions. These regulations provide that these applications would be processed and approved in order of the date of receipt. If applications based on the same renewable electric generation are received on the same date, allowances awarded will be divided evenly between all the relevant applicants unless the Administrator is otherwise directed by all applicants. EPA strongly encourages qualified generators and purchasers of the same electricity generated by qualified renewable energy technologies to coordinate their applications to the

Reserve to avoid confusion over allowance awards.

(c) EPA proposed that applications to the CRER be submitted to the Administrator beginning on January 1, 1993. Eleven commenters suggested that EPA delay this date to allow time for more accurate verification of conservation savings. Commenters had a variety of suggestions for how long to delay the application date, ranging from three to twenty months. Three commenters supported the January 1 date or suggested minor modifications.

A number of commenters argued that since the allowances from the Reserve are allocated on a first-come-first-served basis, there will be pressure to send in applications to the Administrator before complete and accurate verification of conservation savings can be fully assured. Commenters noted that verification of conservation savings is time consuming, particularly verification of savings resulting from complex conservation programs. The commenters also noted that a January 1 application date leaves too little time for verification of savings by State regulatory authorities.

Several commenters argued that an early application deadline penalizes utilities that use more rigorous (and time consuming) verification methods such as metering, bill analysis, and statistical models. Utilities that use simpler and potentially less accurate engineering estimates would be able to apply for allowances sooner. Several commenters also noted that an earlier application date would give an unfair advantage to publicly owned utilities, which are not required to go through state review and verification processes before submitting their applications to EPA.

Response: EPA believes that delaying the application date will encourage good verification of energy savings. The Agency recognizes that evaluation of energy savings requires time for data collection and analysis. Although States are not required to file their applications on the application date, there would be an advantage to filing earlier because allowances are awarded from the Reserve on a first-come-first-served basis. Moreover, because EPA is not mandating a single verification methodology, there could be an unfair advantage for utilities in States that allow verification methodologies that take less time to implement.

The Agency believes that a delay of the application date by six months would provide a reasonable amount of time for States and utilities to complete verification of energy savings. Therefore, § 73.82(g) of these regulations allow utilities to submit applications beginning July 1, 1993, and on July 1 of each subsequent year for the savings achieved in the previous year. (For example, an applicant could apply for savings achieved in 1993 on July 1, 1994.)

Because these rules delay the annual application date by six months to allow more time for verification of savings, EPA believes it is now more likely that the Reserve will become oversubscribed by more than one applicant on a single day than was anticipated under the proposal. (EPA does not anticipate that an oversubscription will occur during the first several years of applications.) A January 1 application date would have led to a more gradual stream of applications over the first part of the year as utilities and their State commissions completed verification of the previous year's energy savings at different times.

Accordingly, § 73.84(f)(1) of the final rule provides that in the event that the Reserve becomes oversubscribed by more than one applicant on a single day, the allowances remaining in the Reserve will be distributed on a pro rata basis. EPA believes that this method for allocating allowances is administratively simple and is appropriate for the Reserve. EPA also considered other methods, such as a lottery, for allocating allowances from the Reserve when it is oversubscribed. However, unlike the Phase I extension provision where 100 percent of the incentive allowances are expected to be claimed on the first day of application, EPA expects that a relatively small portion of the Reserve allowances will remain when it becomes oversubscribed. Thus, because of the relatively few allowances at stake, EPA does not believe that the extra administrative burden of a public lottery would be merited.

F. Return of Auction and Direct Sale Proceeds Under Subpart E

Under subpart E, which was previously published as 40 CFR part 73, in 56 FR 65592–65607, December 17, 1991, EPA must return the proceeds from the auction and direct sale within 90-days of the conclusion of the auction or sale. EPA is planning to return the proceeds by sending a proceeds check to the designated representative for each unit. Until the unit has filed a certificate of representation for the designated representative under subpart B of part 72, EPA will not know the person to whom the proceeds check must be sent. Therefore, EPA will hold the proceeds check until a certificate of representation is filed with EPA. Because EPA will be selling allowances in the advance auction that are taken from Phase II units, and because EPA cannot pay any interest on the proceeds, Phase II units are encouraged to submit a certification of representation for the designated representative before the first auction in March 1993.

V. Discussion of Changes to Part 75—Continuous Emissions Monitoring

This part of this final rule explains the major changes made to part 75, the proposed Continuous Emissions Monitoring (CEM) rule, in response to public comment.

Some structural changes are incorporated into the final CEM rule. First, many of the general provisions contained in subpart A of the proposed CEM rule, such as definitions and abbreviations, have been consolidated for the Acid Rain Program in subpart A of part 72. Second, the proposed rule had only two subparts (A—General and B—Standards); the final rule recognizes that many of the provisions can be grouped functionally into several subparts: subpart B—Monitoring Provisions, incorporates §§ 75.11–75.16 from the proposed rule; subpart C—Operation and Maintenance Requirements, incorporates §§ 75.18–75.20, as well as the procedures for proposing alternatives to the ASTM methods that were originally contained in § 75.21 in the proposed rule; subpart D—Missing Data Substitution Provisions, consolidates the missing data procedures that were located throughout the monitoring provisions, §§ 75.12–75.16 in the proposed rule; subpart E—Alternative Monitoring Systems, incorporates the provisions originally contained in § 75.21 in the proposal; subpart F—Recordkeeping Requirements, incorporates the provisions originally contained in § 75.22; and subpart G—Reporting Requirements, contains the provisions in § 75.23.

While the Appendices have not been reformatted, two new appendices have been added: A new Appendix E (Optional NO_x Emissions Estimation Protocol for Gas- and Oil-Fired Peaking Units), as well as Appendix G (Optional determination of CO_2 Emissions). These appendices were created for this final rule, in response to comments. As a result, the old Appendix E from the proposed rule (Conversion Procedures) has been moved in the final rule to Appendix F.

In the final rule the term "designated representative" now often appears in places where the term "owner or operator" appeared in the proposed rule. As the official responsible for

meeting the reporting requirements under the Acid Rain Program, the designated representative represents the owner and operator when reporting is required. The term "owner or operator" is used in the final rule when action is specifically required at the source.

Overall, the proposed CEM rule received more than 2,700 comments, or approximately 35 percent of the total number of comments received on the proposed core rulemaking package. Approximately 70 percent of the comments received on the proposed CEM rule fell into eight major issue categories: certification and recertification, relative accuracy and Relative Accuracy Test Audits, bias test and bias adjustment factor, flow monitoring, alternative monitoring systems, missing data procedure, exceptions to monitoring with CEMS, and Quality Assurance/Quality Control issues (including calibration testing). Responses to public comment on these major CEM rule issues are discussed below.

A. Certification and Recertification Issues

There were numerous comments related to the certification and recertification of CEM systems. The comments fell into roughly two broad comment categories: notification and Administrator response requirements, and recertification. The EPA's intent is to foster a cooperative environment where the sources seek to initiate, and work through, the process of certification as soon as possible with the appropriate certifying Authorities. The EPA believes that this cooperative effort involving frequent and open communication between sources seeking certification and the certifying authorities will facilitate the start up of the program.

(1) Notification Requirements and Administrator Response

Issues: A number of commenters indicated that the time needed for the Administrator to respond to a certification request coupled with a 30 day notification-of-testing requirement along with, at a minimum, a 7 day certification test would force sources to initiate a CEM certification almost 6 months in advance of the deadline by which the Act states a CEM must be certified. Commenters also indicated that it was unclear as to the procedures a source could follow if, during the course of a certification test, a unit was determined to be failing that test or what to do in the event certification test dates need to be adjusted after notifying the appropriate authorities. Furthermore, commenters had concerns with the requirements placed on new units that would be coming online in the future.

Response: EPA has clarified in the accompanying rule when a new unit would need to be certified. This requirement is based upon an analysis of the intent of the Act to account for all emissions from affected sources in a two phased approach and with the recognition that not all affected sources will be operating prior to January 1, 1995. Furthermore, this rule takes into account the comment that some types of units that will be affected can be brought online and turned over to the dispatcher in a relatively short period of time and that units typically need to burn some fuel prior to a time when a CEM system can be in and certified.

EPA analyzed the reporting, notification, and approval procedures, time frames, and burdens on the sources and governmental resources in response to the comments received. EPA has modified the certification forms and process to include more interaction between sources and agencies, however the overall time that this rule is reserving for notification of testing and review of completed certification submittals has been *reduced* relative to the statutorily mandated deadlines for units to have certified CEM systems operational. EPA analysis indicates that the new procedures and forms will require 45 days to properly review at a minimum and should, therefore, be submitted at least that far in advance of the commencement of certification testing. However, EPA believes that (and actively encourages) the cooperative procedures developed will actually be initiated far in advance of 45 days and proceed in a series of logically derived steps that will culminate in a fully successful certification.

This cooperative, multi-step process also leads the agency to believe that monitors can be provisionally certified upon the successful completion of certification testing and that if a unit is determined to be failing a certification test that a new series of tests can be commenced immediately as part of the certification effort. The Administrator will still need to reserve the full 120 days from receipt of a complete certification request to perform analysis of test results before a final notice of certification can be served to a particular CEM system; however, all data collected from a provisionally certified system that is subsequently fully certified is valid data and provisional certification meets the requirements of the Act with respect to the dates by which units must install and operate CEMS, quality assure the data and keep records and reports.

For this reason, EPA has determined that the certification testing must be completed and the system(s) must have initiated full, quality assured operation by the statutory deadlines. However, the unit may submit its certification request complete with the required test reports up to 30 days thereafter. This change accommodates the time normally necessary to prepare those reports and the request. The Administrator's review will take place within 120 days of receipt of the complete package. Additionally, if a future audit of the system (a certification report) uncovers a discrepancy or poor performance that requires recertification of the CEMS, the emissions will be determined using the appropriate missing data procedures, prospectively, upon receipt by the owner or operator of the Agency's determination until the recertification testing is successfully completed.

EPA believes that these modifications fully address the commenters concerns while addressing the legislative mandates and insuring the integrity of a CEM system certification.

(2) Recertification

Issues: A number of issues were raised by commenters related to recertification. Among the issues raised was that it was unclear as to what actually triggered the need for a recertification, the time needed to notify of recertification testing, approval time needed, recertification time-frames in the event of an emergency, and the types and numbers of tests required for recertification.

Response: EPA has further clarified the sentence in the proposal that indicated when recertification becomes necessary. Essentially any change, other than routine maintenance or quality assurance activities, that affects the monitors measuring systems or analysis systems in such a way that measurements or calculations have changed, or potentially could have changed significantly, triggers a recertification. The EPA continues to feel that the nature of Title IV and its reliance on strict accountability of all emissions necessitates a reliance on certified measurement devices and calculation methodologies, hence, forcing the agency to require recertification whenever either or both of these items are significantly modified in any particular CEM system.

EPA is persuaded by public comment and analysis that the notification of recertification testing dates should be shortened to 7 business days prior to the commencement of a scheduled

recertification testing period and that in the event of emergency testing (e.g. testing due to significant repairs after a lightning strike or tornado damage to a CEM) notification should be made to the appropriate authorities no later than 2 working days following the emergency and indicating when testing is expected to be completed. EPA believes that this compromise addresses the commenters concerns about monitor availability and the long lead times that would put data obtained during this time into an uncertain state as to acceptability while also preserving the needs of the regulating authorities to be aware and available for a cooperative effort to recertify as quickly as possible while preserving the intent of the Act to account for all emissions.

B. Relative Accuracy and RATA Testing

(1) Relative Accuracy Standards for SO_2 and NO_x

(a) Normal emitters. The proposed rule required SO_2 monitors and NO_x monitoring systems to meet a 10 percent relative accuracy (RA) standard in Phases I and II of the Acid Rain Program. Some commenters argued that the 10 percent standard was, at best, premature and, at worst, too stringent, and that it would result in high failure rates due to the variability of the reference method, leading to wasted resources for retesting. They proposed that the standard should be set initially at 15 percent. Other commenters indicated that the standards were either achievable or not sufficiently stringent.

Response: The EPA analyzed data from relative accuracy test audits (RATAs), conducted during 1984–1990 at non-low-emitting subpart Da units. ("Subpart Da" units refer to electric utility fossil fuel steam generators, covered under 40 CFR part 60, subpart Da of the New Source Performance Standards (NSPS).) This analysis indicates that SO_2 CEMS, measured in ppm, achieved the 10 percent standard in 89 percent of the RATAs, even though meeting a 10 percent relative accuracy standard was not required. Extensive field tests at one unit confirmed these results. In relative accuracy testing performed over a 9 week period, the installed SO_2 CEMS, measuring in ppm, passed the 10 percent RA standard in 98.2 percent of the RATAs constructed from 176 runs conducted at the test site. These results were obtained by moving a 12-run window through the 176 runs and applying the test procedures prescribed in the proposed regulations. For each incrementing of the window, relative accuracy results were computed, producing a total of 165 RATA tests for the entire data stream. This procedure revealed that 95.8 percent of the RATAs achieved RA ≤7.5 percent, and 82.4 percent of the RATAs achieved RA ≤5 percent. Comparable results for the NO_x CEMS measured in lbs/MMBtu were 100 percent achieving RA ≤10 percent; 97.6 percent achieving RA ≤7.5 percent; and 86.7 percent achieving RA ≤5 percent. EPA believes that these test results support the proposed 10 percent RA standards for both SO_2 and NO_x, which are retained in the final rule.

(b) Low emitters. For SO_2 concentrations less than or equal to 250.0 ppm, the proposed rule allowed use of an alternative accuracy standard: The mean of the CEMS measurements had to be within ±15.0 ppm of the reference method mean. Commenters pointed out that low emitting units should have the option of using either the normal relative accuracy standard or the alternative standard. They also noted that the low emitter accuracy provision should be added to the "out-of-control" provisions in appendix B.

Response: EPA agrees. For units whose monitor measurements of SO_2 during the RATA are close to 250.0 ppm, the ±15 ppm specification could represent a more stringent standard than the 10 percent RA specification. This is not intended. Therefore, the final rule clarifies that either the low SO_2 emitter accuracy standard or the normal SO_2 RA standard can be used. As the commenters recommended, the low SO_2 emitter accuracy standard has been added to the "out-of-control" provisions in appendix B.

The proposed rule also allowed use of an alternative accuracy standard for NO_x emissions less than or equal to 0.50 lb/MMBtu: The monitoring system mean had to be within ±0.05 lb/MMBtu of the reference method mean. A number of commenters noted that the low NO_x emitter threshold of 0.50 lb/MMBtu must be in error, because it is the same level as the statute's presumptive NO_x limit for wall-fired boilers and is higher than the 0.45 lb/MMBtu limit for T-fired units. The proposed low NO_x emitter threshold would, in effect, define all units affected by the NO_x emission limits as low NO_x emitters.

Response: Clearly, this was in error. In the final rule the low NO_x emitter accuracy standard is revised as follows: For units emitting less than or equal to 0.20 lb/MMBtu NO_x, the NO_x monitoring system mean must be within ±0.02 lb/MMBtu of the reference method mean value. This is analogous to the low-emitter accuracy standard for SO_2. Similarly, the low NO_x emitter accuracy standard has been added to the "out-of-control" provisions in appendix B.

(2) SO_2 and NO_x RATA Frequency

For SO_2 and NO_x CEMS, the proposed role required semiannual RATAs, except when an SO_2 monitor or NO_x monitoring system achieves a RA of less than or equal to 7.5 percent. In such cases, the proposal extended the time period for the next RATA to 12 months instead of six. Many commenters supported the proposed RATA frequency incentive system, which linked decreased RATA frequency to superior RA test results. These commenters suggested expanding the incentive system to include low emitters. There were, however, a number of commenters who categorically opposed requiring a RATA more often than annually, whether there was an incentive system or not. They maintained that more frequent RATAs would not improve the accuracy of CEMS data and would be unnecessarily costly. Still other commenters proposed basing RATA frequency on results of daily calibration error tests rather than on RATA results.

Other commenters supported requiring quarterly RATAs until test results justified less frequent RATAs. One group maintained that RATA tests were snapshots and that a series of tests, over four quarters, showing consistent or steadily improving results was a better indicator of CEMS performance than one RATA per year. This commenter supported a phased approach that would require quarterly RATAs for all Phase I affected units with less frequent testing in Phase II, pending Phase I results. This commenter also recommended adoption of an incentive-based system that would credit and debit allowances, based on a unit's performance compared to the best performers in the industry.

Response: Alter considering the range of comments, EPA has decided to retain the RATA frequency and incentive system as proposed and to provide an analogous incentive system for low-emitters. Extending the incentive system to units where SO_2 concentrations are low should stimulate improved RA, while reducing the frequency, and hence cost, of performing RATAs at these units. As designed, the low SO_2 emitter incentive system should yield the same proportion of less frequent RATAs as the incentive system for normal SO_2 emitters. If a unit's mean SO_2 concentration is less than or equal to 250.0 ppm and within ±8.0 ppm of the reference method mean, the next required RATA test would be required in 12 months rather than six.

The Agency decided not to base the RATA frequency on the daily calibration error test results, as suggested, because calibration error tests do not test CEMS for many potential sources of error, making them an inappropriate basis for determining RATA frequency. EPA also rejected the suggestion of universal or phased-in quarterly RATAs, as imposing a greater financial and regulatory burden on industry than necessary, without significantly improving the accuracy of the emissions data. Finally, the allowance-based incentive system proposed by one commenter appears to be a promising approach but would be too complex and difficult to implement, particularly considering the time requirements imposed by statutory deadlines.

(3) Combined SO_2-Flow

The proposed rule stipulated that, starting on January 1, 2000, the combined SO_2-flow monitoring systems would have to meet a 10 percent RA standard. Many commenters criticized this proposed combined relative accuracy test. These commenters stated that because each monitor is required to also pass QA/QC tests individually, the combined RA is merely a mathematical exercise, which, judging from existing data, is technically insupportable and likely to yield erratic and meaningless results. These commenters also maintained that the combined RA test was redundant, unnecessary, and could lead to expensive and needless re-testing. Others argued that the 10 percent combined RA standard may not be achievable in light of measurement errors associated with reference method procedures and that any future combined SO_2/flow RA standard should not be less than 20 percent. One commenter stated that the proposed 7-day certification test for the combined SO_2/flow system would be costly and impossible to pass. Several other commenters recommended that EPA defer promulgating a combined SO_2/flow RA standard until more data was obtained.

However, supporters of the combined RA test were numerous. These commenters maintained that the combined standard would result in more accurate data. Among their proposals were starting the requirement in 1995 rather than in 2000, requiring a combined SO_2/flow RA standard more stringent than 10 percent in Phase I so that the allowance system would not be compromised, requiring a lb/hr RA for SO_2 and a lb/MMBtu RA standard for NO_x, rather than individual monitor RA's, and establishing an alternative combined standard for low emitters.

Response: EPA believes that both individual SO_2 and flow monitor measurements and combined lb/hr SO_2 values derived from those measurements should meet explicit and verifiable accuracy standards. Flow monitor data should meet accuracy standards because, in addition to lb/hr calculations, it is used: (1) In calculating heat input (for reduced utilization), (2) for missing data procedures, and (3) for calculating NO_x penalties. SO_2 monitor data should meet accuracy standards because, in addition to lb/hr calculations, it is used for missing data procedures. The lb/hr values should meet accuracy standards because they are the ultimate measure of environmental impact and the basis for determining compliance with allowances held.

At the same time, EPA agrees with comments noting that there is currently insufficient data to establish a definitive combined SO_2/flow relative accuracy standard. Therefore, EPA is deferring promulgation of a specific combined relative accuracy standard in the final rule, while reserving a section in part 75 for future promulgation of this standard once sufficient data has been accumulated. EPA believes that a combined SO_2/flow RA requirement is an important additional indicator of system performance.

Twenty percent relative accuracy is widely acknowledged as an achievable baseline standard for combined relative accuracy performance, that is in keeping with the combined standard established in EPA's Performance Specification 6 (Appendix B, 40 CFR part 60). Preliminary test data from state programs employing Performance Specification 6 indicate that combined relative accuracies below 10 percent are routinely achieved. In addition, simulation analysis shows that units whose flow and pollutant concentration monitors individually achieve relative accuracies of 10 percent or better almost invariably will meet a relative accuracy standard of 15 percent on the combined test. The EPA is fully committed to promulgating a combined standard once sufficient data has been obtained and evaluated under Phase I of the Acid Rain Program.

(4) Bypass Flues and Peaking Units

The proposed rule would have subjected CEMS on bypass flues and peaking units to the same RATA frequency (quarterly, semiannual or annual) as those on normal stacks and baseload units. Several commenters argued that CEMS on bypass stacks should only have to perform annual RATAs. These commenters also suggested defining RATA testing frequency in terms of unit operating hours, rather than calendar time, and postponing RATAs until the bypass stack was next called into regular operation. Another commenter stated that the final rule should not require a unit to be operated or a pollution control system to be bypassed just to conduct a RATA, since this would result in unnecessary emissions and loss of allowances and might cause a unit to violate its operating permit.

The same commenters and several others noted that it would be very expensive and create needless pollution to run low capacity factor "peaking" units just to conduct RATA tests. These commenters recommended basing a peaking unit's RATA frequency on unit operating hours and performing RATAs on peaking units every two operating years.

Response: EPA agrees that it is not desirable to require a pollution control system to be bypassed solely to perform a RATA. However, the statute requires monitoring of emissions from all affected units and enforcement of performance standards that guarantee accurate emissions measurement.

To reduce the overall time required to perform RATAs on monitors at peaking units and bypass stacks, the final rule requires only a one-level RATA to be performed on flow monitors on peaking units and bypass flues instead of the usual 3-level RATA. EPA believes that it should be possible to schedule RATAs during the normal operation of peaking units and bypass stacks through careful advanced planning.

C. Bias Test and Bias Adjustment Factor

Accuracy in emissions measurements is essential to the complete accounting of all SO_2 and NO_x emissions reductions, stipulated in the Clean Air Act Amendments, and to the effective functioning of SO_2 allowance trading. Consequently, the acid rain regulations proposed that each CEMS satisfy two complementary statistical tests for accuracy both at initial certification and during periodic quality assurance performance evaluations: (1) A relative accuracy test to ensure that all sources of monitor error (both random and non-random) fall below a specified percentage of the average reference method measurements; (2) a bias test to determine if a monitor is measuring consistently low. These two tests are applied to emissions data obtained during the relative accuracy test audit (RATA), a field test procedure that compares at least nine monitor

measurements to contemporaneous measurements by an EPA specified monitoring reference method.

To determine whether a CEMS is measuring consistently low, the bias test relies on the well-established t-test at 95-percent confidence level, applied here to low bias only. The t-test, specified in these regulations, is constructed to ensure that there is at most a 2.5 percent probability of mistakenly detecting low bias during the RATA test.

When low bias is detected, operators have two options: they can remedy the causes of the low bias by fixing a faulty monitor, correcting installation problems, or improving operator practices that may be contributing to the consistently low measurements. Alternatively, they can elect to apply a bias adjustment factor to subsequent emissions measurements reported to EPA. The bias adjustment factor is a multiplier, calculated from RATA data, whose magnitude is directly proportional to the degree of low bias detected during the RATA performance test.

(1) Bias Test

(a) Overview. The EPA received comments both supporting and criticizing the proposed bias test. Numerous commenters supported the proposed bias test as an essential element of a monitoring program. Many others proposed dropping the bias test, arguing that daily quality control procedures offered sufficient safeguards against monitor bias. Still others supported a t-test for bias, but advocated that it be based on data from the daily calibration error test rather than from the RATA test. Some of the commenters, who either opposed the bias test entirely or proposed basing it on calibration data, also advocated applying the RATA-based bias test only at initial monitor certification. Subsequently, they would rely exclusively on quality control procedures or the calibration-based bias test to prevent low bias. Another proposal, by the commenters advocating the calibration-based bias test, was to drop all bias testing requirements when relative accuracy test results fell below some threshold value.

Response: After carefully evaluating each commenter's proposal, data provided by the commenters, data independently collected by EPA, and statistical theory, EPA has decided to retain the proposed t-test for bias and the bias adjustment factor. The EPA's analysis of the specific comments on the bias test is summarized below.

(b) Long-term validity of bias test. Some commenters challenged the ability of a t-test, based on a 4–8 hour RATA, to determine whether a CEMS was producing consistently low measurements (i.e., bias) over the long run. They maintained that a bias test, based on RATA data, was only a snapshot that would produce inconsistent results if performed on the same monitor on successive days. To support their argument, they provided bias test results from two plants.

Response: The EPA found one of the commenter's data sets inadequate. EPA believes that the data was not sufficiently extensive to support the commenter's argument, since it consisted only of a total of six RATAs: Two successive RATAs conducted on August 18–19, 1987, May 26–27, 1988, and September 20, 22, 1988. Further, there was insufficient documentation to determine whether the variability in the test results was due to the test procedure or factors that may have introduced bias into the system. To analyze the long-term variability of bias test results, the factors subject to variation must be strictly controlled or, at least, documented. If factors such as monitor location, operating procedures, and unusual interventions (e.g., lightning strikes) vary from test to test, then variations in test results may not reflect variability inherent in the statistical test but variability in the monitoring environment that may have produced systematic error reflected in the bias test results. Without additional documentation it is not possible to determine whether changes may have occurred that could have introduced bias into the system.

The second set of bias test results cited by the commenter contradicts the commenter's contention: the same flow monitor consistently failed the bias test in RATAs performed on four successive days. While the commenter argues that the test results show that the bias adjustment factor is "unstable," the results clearly do not support the commenter's position on the variability of bias test results.

The t-test is a well established and widely accepted statistical procedure for detecting bias. As noted above, the statistical premises underlying the form of the t-test specified in the regulations limit the likelihood of mistakenly detecting low bias to no more than a 2.5 percent probability. Thus, a high degree of assurance is built into the test itself that, over the long run, this statistical test will detect bias that is actually present in the system, not "random measurement error" as the commenter claims.

In the preamble to the proposed rule, it was noted that EPA collected and analyzed data from RATAs performed between 1984 and 1990 primarily at units subject to Subpart Da requirements and found that 70 percent of the SO_2 RATAs, measured in ppm, passed the proposed t-test for bias. These results were obtained from RATAs performed at a time when CEMS technology and operational experience were in an earlier stage of development than they are today.

An extended field test at one unit also reflected consistency in the bias test results. Following the calculation procedures prescribed in the proposed regulations and moving a 12-run window through a 176-run data stream, 165 RATAs were produced for the 9-week testing period. The bias test pass rate was 73.3 percent for the SO_2 CEMS, measured in ppm, and 99.4 percent for the NO_x CEMS, measured in lbs/MMBtu. Bias test failures were clustered, not randomly distributed, along the data stream, providing a further indication that the t-test was detecting actual systematic error, not random measurement error. It is also noteworthy that 98.2 percent of the SO_2 CEMS and 100 percent of the NO_x CEMS passed the 10 percent relative accuracy test.

In the preamble to the proposed rule, EPA noted that "it can be assumed that subsequent improvements in monitor technology will yield even better performance on the bias test." RATA data, submitted to EPA for a new CEMS technology, based on ultraviolet/differential optical absorption spectroscopy, convincingly supports this prediction and displays consistency in the bias test results. Of the 16 RATAs performed on this monitoring system, 87.5 percent passed the bias test, while achieving an average relative accuracy of 6.9 percent.

Thus, EPA believes that both statistical theory and field test results show that the bias test is a sound and effective statistical procedure for detecting consistent measurement error in the long-term operation of a CEMS.

It should be noted, however, that EPA is sympathetic to the commenter's concern that data used in the bias test be "sufficiently representative of long-term monitor performance." From a strictly statistical standpoint, the larger the sample size, i.e., the longer and more frequent the RATA, the more representative the RATA will be of long-term monitor performance. For this reason, EPA considered requiring quarterly RATAs in all cases. However, the agency chose to balance statistical considerations against the burden

imposed on the regulated community. The agency believes the 9-run RATA supports statistically credible results at the least cost to society.

(c) Impact of reference method variability on the bias determination. Some commentators argued that inherent variability in the reference method performance could inappropriately cause CEMS to fail the bias test even when the CEM measurements were not biased relative to the true emissions concentration. They argued that the variability among reference monitors should be accounted for by adjusting the t-test. The potential for a CEMS to fail the bias test by being compared to a certified reference monitor was investigated in the above referenced field study. In this study, RM measurements were taken simultaneously by four laboratory test teams, and compared with an operating plant CEM. The field results demonstrated that the low bias test results were consistent, regardless of the particular reference monitor chosen. Further, the variation associated with RM-to-RM comparisons exhibited good reproducibility, suggesting that laboratory variability did not inappropriately influence the bias determination. This result is encouraging, and strongly supports the choice of the RMs and its use. However, detailed review of the RM data produced some troublesome results that warrant concern. While the variance across RMs relative to the mean difference in RM readings was low, bias could be calculated between the different reference monitors (in as many as 50% of the comparisons). Concern has been expressed that the high frequency of bias in comparisons among reference monitors occurred despite the reproducibility of results among reference monitors noted above because of low variance in reference method test data. Additionally, some commenters expressed concern that bias was triggered at lower emissions levels (below 200 ppm).

While the Agency currently supports the bias test, the data suggest that further study is appropriate. The Agency, in consultation with the Department of Energy, will initiate additional field studies as soon as possible to determine whether there are statistically significant variances in the reference monitors. These field studies will attempt, among other things, to distinguish between the variability in the reference monitor reading attributable to measurement error and the variability due to the choice of reference moritor among those certified by the agency. The studies will also assess whether any adjustments indicated are technically unnecessary or infeasible to properly determine bias. Finally, the field studies will also investigate possible differences in bias test failure rates by emissions concentration levels. The Agency will initiate the field studies as soon as possible to determine whether the bias test should be adjusted to compensate for statistical variances in the reference method. These studies will be completed by October 31, 1993. Within 90 days of the completion of the studies, the Administrator shall publish by notice of proposed rulemaking in the **Federal Register** his determination of whether there should be an adjustment of the bias test. The rulemaking shall be completed within 9 months thereafter. EPA will also adjust the t-test used to certify alternative monitoring systems if a bias t-test adjustment is made.

(d) Statistically significant vs. practically significant measurement differences. Some commenters argued that the paired t-test may identify measurement differences between the CEMS and reference method that are statistically significant but that are not necessarily practically significant.

Response: The fact that the bias adjustment factor is directly proportional to the magnitude of the measurement differences ensures that sources will not be unfairly penalized for differences that are not practically significant. If, as the commenter contends, the measurement differences are not practically significant, then it follows directly from the commenter's argument that the bias adjustment factor will not be practically significant, and, consequently, the adjustment of subsequent measurements will also not be significant.

(e) Bias test results for volumetric flow monitors. Several comments specifically questioned the application of the bias test to flow monitors. They maintained that the proposed bias test was beyond the current capabilities of volumetric flow monitors. They noted that less than 30 percent of the RATAs in EPA's pre-proposal flow monitor database passed the bias test.

Response: A number of utilities have subsequently provided EPA with field test results from 56 additional flow monitor RATAs, bringing the total number of RATAs in the database up to 73 from the original 17. In evaluating the tests included in this database, several considerations are relevant. The flow monitors in this database were not long-standing installations, but were still in a shake-down phase where various utilities were evaluating competing brands in anticipation of purchasing one of them. Thus, several competing flow monitors were installed on a single stack and put through their paces under extreme testing conditions, without the benefit of installation fine-tuning that would accompany an actual installation. Shake-down testing of this kind produces poorer test results than can be expected when the selected monitor is finally installed and many of the problems that emerged during shake-down are corrected. Furthermore, because gas stratification is so important in measuring volumetric flow and each site has a unique stratification profile, flow monitor performance tends to be very installation specific. As a result, it is not uncommon that one monitoring technology performs well at one unit, while a different technology is better suited for another unit.

With this in mind, it is noteworthy that at each utility unit where multiple brands of flow monitors were tested, at least one flow monitor model had a bias test pass rate of better than 80 percent. In fact, at four of the five utilities testing multiple brands of flow monitors, at least one monitor model had a 100 percent pass rate on the bias test. Excluding one manufacturer's monitor that appears to have had recurring difficulty eliminating low bias, 65.1 percent of the remaining 43 RATAs passed the bias test.

These test results provide additional support for EPA's conclusion that the bias test performance standard is within the technical capabilities of current flow monitoring technology.

(f) Exemption from bias test. Some commenters proposed retaining the bias test but exempting units that achieve excellent results on the relative accuracy test.

Response: EPA does not support this suggested exemption. Under the proposed regulations, units were already rewarded for excellent relative accuracy results by being allowed to perform less frequent RATAs. Because bias represents systematic rather than random error, it is correctable and, therefore, should be eliminated to ensure that the monitoring program provides the level of accuracy required for compliance with the emissions standards mandated by the Clean Air Act Amendments and for effective functioning of the allowance trading program.

Furthermore, waiving the test for low bias could have serious environmental consequences even when relative accuracy is very low. As its name implies, relative accuracy reveals the proportional relationship between inaccuracy in the CEMS and the average emissions level of the unit being tested.

For high emitters, e.g., units whose mean SO_2 emissions concentration could measure as high as 3000 ppm, the absolute magnitude of the inaccuracy may be environmentally significant, even though its relative size (i.e., the relative accuracy) is small. Thus, excellent relative accuracy can obscure the presence of environmentally consequential and operationally correctable inaccuracy that only the bias test will reveal.

(g) Daily calibration error test and periodic quality control (QC) instead of the bias test. One commenter called for replacing the proposed bias test with "the daily calibration error test and periodic QC."

Response: EPA supports the use of the calibration error test and periodic QC as important components of a comprehensive quality assurance/quality control (QA/QC) program. However, by themselves QA/QC procedures and calibration testing can neither detect nor eliminate many important sources of bias. For example, calibration testing is unlikely to detect bias attributable to incorrect calibration gas values, uncorrected sensitivity to pressure and temperature, non-representative sampling, interferences from flue gas constituents, or scrubbing by precipitates on the particulate filter. Without a means to detect these sources of bias, QA/QC procedures would be blind to their presence and would be unlikely to correct the problem. Only the RATA-based bias test, which compares the installed CEMS to an independent reference monitoring method under actual operating conditions, can detect all major sources of systematic measurement error that constitutes bias. If the calibration and QA/QC procedures proposed by the commenter are conscientiously implemented in concert with periodic RATA-based bias and relative accuracy tests, monitor accuracy as required by the Clean Air Act Amendments should be achieved.

(h) Calibration-based bias test and adjustment factor. As an alternative to the RATA-based bias test, some commenters proposed retaining the one-tail t-test but applying it to data obtained from the daily calibration test instead of data from the periodic RATA. They supported their proposal by noting that the pass-fail rates on the two tests are comparable. In addition, they noted that the bias adjustment resulting from their alternative bias test was substantially lower on average than that adjustment factor derived from the RATA-based test.

Response: The suggested calibration-based bias test is flawed on engineering and statistical grounds. Two problems with a cal-gas based bias test from an engineering standpoint are its lack of an independent test procedure and failure to detect all sources of bias. First, to objectively quantify CEMS accuracy requires an independent test. That is, the standard against which the CEMS is checked should share no components in common with the CEMS. For the RATA test, where the reference method shares no components with the installed CEMS, this condition holds. In contrast, the calibration test is not an independent test, since the same CEMS used to perform emissions measurements is also used to measure calibration gas concentration. Second, the cal-based bias test is capable of detecting only a few of the potential sources of CEMS bias. The cal-based test should be able to detect bias caused by electronic/optical drift, improper interfacing of the analyzer and the data acquisition system, and loss of gas by absorption or adsorption. It may be able to detect bias caused by system leaks and plugging and by improper microprocessor corrections. However, it is unlikely to be able to detect bias caused by incorrect calibration gas values, uncorrected sensitivity to pressure and temperature, non-representative sampling, interferences from flue gas constituents, or scrubbing by precipitates on the particulate filter. In essence, the cal-based bias test simply detects consistent daily electronic/optical drift and operator introduced error, not full system bias.

From a statistical perspective, there are several serious drawbacks to use of the cal-gas based bias test. First, because the calibration procedure adjusts the CEMS based on the previous day's drift, the test procedure itself introduces time dependencies into the data, possibly limiting the applicability of the t-test. This contrasts with the RATA-based bias test. While the process being measured may display time dependencies, the RATA-based test procedure is unlikely to introduce time dependencies into the data.

Second, if the calibration procedure is not completely automated and an operator adjusts the CEMS each time a calibration is performed, it is difficult to determine whether the t-test is picking up bias in the installed CEMS or systematic error introduced by the operator's role in the test procedure. Unlike the RATA-based bias test, where the test protocol and reliance on an independent reference method minimize the chance of systematic error being introduced by the tester, there are no such inherent procedural safeguards in the cal-gas bias test. An operator's intervention in the calibration test also raises the possibility of obscuring of bias through over-adjustments of the daily measurements on which the bias test depends. For example, if an operator repeatedly over-adjusts up one day and over-compensates low the next day, the presence of bias is likely to be hidden by the oscillating over-adjustments.

Besides these problems with the cal-based bias test, the commenter's observation that the cal-based test's pass/fail rate is close to the pass/fail rate on the RATA-based bias test is irrelevant. The two tests are measuring two different phenomenon, which are not necessarily correlated. Any closeness of pass/fail rates is therefore likely to be purely coincidental.

(i) Performing RATA-based bias test only at initial certification. Some commenters proposed that the RATA-based bias test only be performed at initial certification of the CEMS. Some of these commenters proposed using a bias test based on daily calibration data after certification; others proposed using the calibration error test and routine quality control procedures to prevent bias.

Response: While it is particularly important to perform the RATA-based bias test at initial certification of the monitor, when many installation-related sources of bias can be detected and overcome, periodic RATA-based bias testing is equally important after installation, because it represents the only reliable way to detect and correct bias that can arise once the CEMS begins operation. Routine occurrence (like precipitate buildup on the probe) and unpredictable events (like lightning strikes) can cause installation and operating conditions to change over time, and these changes can cause monitor bias which could go undetected without periodic RATA-based bias testing. As explained above, neither calibration error testing nor bias testing based on calibration data can detect many of the major sources of bias that arise during initial installation or extended operation. EPA believes that periodic RATA-based bias testing is the most reliable way to determine whether bias has developed in the monitoring system.

(2) Bias Adjustment Factor: Comments and Responses

Comments for and against the proposed bias adjustment factor were about evenly divided. Many commenters supported the adjustment as an important element in an effective, yet flexible, monitoring program. Many others recommended dropping the bias adjustment factor and emphatically

stated that bias test failure should not result in the monitor being designated "out of control," as was once contemplated, but not subsequently proposed, as an alternative to the bias adjustment. A number of commenters proposed variations on how the adjustment should be computed and when it should be applied.

(a) Technical justifiability of the adjustment factor. Some commenters contended that the bias adjustment, based on the RATA test, is technically insupportable. In part, their position rests on the argument, summarized above, that the RATA-based t-test itself is not an appropriate measure of bias. Furthermore, the commenters maintained that an adjustment factor derived from a nine-run RATA "would result in an artificial inflation of reported emissions that would remove SO_2 allowances from the marketplace."

Response: It should be noted that the adjustment factor is a regulatory mechanism intended to add flexibility to the performance testing program. The adjustment factor gives units an alternative to eliminating the sources of bias, while minimizing the likelihood that emissions measurements will be under-reported. When low bias is detected by the t-test, a source can choose either to find the cause of the problem and fix it or to adjust subsequent emissions measurements by a factor commensurate with the extent of bias detected at the time of the RATA. Deriving the bias adjustment factor directly from the RATA results means that there is no "artificial inflation," over-compensation, or conservativeness involved, because it reflects conditions exactly as they are at the time of the RATA.

EPA's analysis indicates that the average bias adjustment factor is likely to be below 5 percent. In the SO_2 lbs/MMBtu RATA database, the average bias adjustment factor was 4.4 percent for RATAs that met the RA≤10 percent relative accuracy requirement but failed the bias test. For these RATAs the adjustments ranged from 0.89 percent to 6.99 percent. Thus, the bias adjustment factor would appear to provide utilities with a reasonable and practical alternative to repair a low biased CEMS.

(b) Bias adjustment factor for high bias as well as low bias. Some commenters proposed that the bias adjustment factor should not only be applicable to monitors that measure consistently low (i.e., low biased CEMS), but also to those that measure consistently high (i.e., high biased CEMS).

Response: EPA believes this modification is neither necessary nor desirable. As proposed in the regulations, the bias adjustment factor provides an incentive for eliminating low bias, comparable to the financial incentive that the allowance market gives to eliminating high bias. In tandem, these twin incentives will provide a self-enforcing mechanism, virtually free of regulatory intervention, for minimizing monitor bias—both high and low. An adjustment for high bias would remove the self-enforcing market incentive for eliminating high bias and require the imposition of a more burdensome administrative procedure for controlling high bias. There is also no environmental justification for an adjustment factor for high bias.

(c) Bias adjustment for flow monitors. A number of flow monitor vendors expressed concern that bias test results and the corresponding bias adjustment are likely to vary substantially at the three different load levels required for the flow monitor RATA test. It was feared that requiring a bias adjustment factor to be derived only at the normal load level might inadvertently distort monitor accuracy at other load levels.

Response: The bias adjustment factor specified in the proposed regulations is not a mechanism for calibrating the flow monitor to the reference method over the load range. Such a calibration procedure can be incorporated into a manufacturer's proprietary instrumentation, for example, by means of a regression curve, as suggested by one vendor. Rather, the bias adjustment factor is simply a regulatory mechanism, giving sources an alternative to eliminating the causes of bias, while minimizing the likelihood that flow measurements will be under-reported. EPA requires the flow monitor bias test to be computed only on the RATA data collected at the normal operating level. However, if the bias test is failed at normal load, the bias adjustment to be applied to subsequent data are the largest of the adjustments derived from the low, normal, and high-load RATAs. This should avert under-reporting of flow measurements, in light of the commenters' contention that the magnitude of the bias adjustment factor may not be uniform across load levels. In addition, during Phase I of the Acid Rain Program, EPA will analyze data from the low- and high-load RATA tests to see if bias test results at these loads would have diverged substantially from those obtained at the currently required normal load level and will continue to evaluate the bias test requirements for flow monitors.

The extensive analysis of comments on bias described here has led EPA to conclude that the RATA-based bias test and the bias adjustment factor are sound and essential elements in a performance testing program for assuring the accuracy of CEMS. Unlike other alternatives proposed, the RATA-based bias test provides a procedure for detecting systematic error that tests the full system against an independent reference method monitoring system under actual operating conditions. In tandem with the bias adjustment factor, this procedure represents a cost effective and self-enforcing mechanism for eliminating systematic error from monitoring systems.

D. Flow Monitors

Commenters raised seven major issues related to flow monitoring. Three pertained to the RATA (relative accuracy test audit) for flow monitors: Proposed changes to the relative accuracy standard; the requirement that RATAs be performed at three load levels; and the required frequency of RATAs. In addition, commenters charged that there was not a "level playing field" for all flow monitor technologies, asserting that the proposed calibration test for flow monitors was discriminatory against specific technologies. Commenters also questioned the need for an orientation sensitivity test. There were also comments on the proposed definition of "span" for flow monitors. Finally, there was a comment on the petition process for alternative monitoring locations for flow monitors.

(1) Relative Accuracy Standards

The proposed rule required that flow monitors meet a 15 percent relative accuracy (RA) standard through December 31, 1999 and a 10 percent RA standard thereafter. Because the mathematical structure of the RA statistic makes it very difficult to achieve the 10 percent RA standard when the flow rate is low, the proposed rule would have allowed flow monitors to be within ±1 foot per second (fps) of the reference value, rather than achieving 10 percent RA, when the flow rate was less than or equal to 10 fps.

EPA received many comments regarding the proposed flow monitor RA standards. Some commenters maintained that the proposed flow monitor RA standards were too stringent and could not be supported with EPA's limited database. Some of these commenters also claimed that the proposed RA standards were beyond the capabilities of current flow monitoring technology. Several commenters suggested extending the 15 percent RA standard through Phase II; two other

commenters proposed a 20 percent RA standard throughout Phases I and II.

However, other commenters stated that the proposed flow monitor RA standards were not stringent enough. They asserted that a 10 percent standard for Phase I was clearly achievable based on the evidence cited in the preamble to the proposed rule. One commenter stated that a 15 percent RA standard was very liberal, while another claimed that the flow monitor Phase I RA standard could be tightened to better than 5 percent.

Response: Eighty-two percent of the 73 RATAs now in the EPA database pass a 15 percent RA standard, and 70 percent pass a 10 percent standard. The EPA believes that these test results justify retention of the proposed RA standards in the final rule, except the low flow standard, which is discussed below.

Some commenters urged EPA to change the low flow accuracy standard from ±1 fps to ±2 fps and to clarify that a unit with low flow conditions may apply either the low flow accuracy test or the standard RA test.

Response: Upon further consideration of the measurement capabilities of flow monitors, EPA has decided to accept the commenters' suggestion to change the low flow accuracy standard to ±2 fps for flows less than or equal to 10 fps. The final rule will also make it clear that in low flow situations, units can satisfy their relative accuracy requirements by achieving either the ±2 fps specification or the applicable RA standard. The EPA believes that this change better accommodates the low flow thresholds of current flow monitoring technologies and should prevent unwarranted RATA failures.

(2) Three-Level Relative Accuracy Test

The proposed regulations would have required the operator to perform separate relative accuracy tests on flow monitors at low, normal, and high flow rates or at low, normal, and high unit operating levels. The three-level relative accuracy tests were to be conducted at the initial certification of the flow monitor and annually thereafter as part of the quality assurance performance requirements for flow monitors.

Two commenters supported the concept of an annual 3-level audit for flow monitors. Others suggested that the 3-level flow monitor RATA not be performed annually, but only (1) at certification and (2) when a change in stack/duct configuration necessitated recertification of the monitor. To support their position, these commenters cited the additional testing costs of multiple RATAs, the small likelihood that the flow profile would change absent stack/duct changes, and the potential interference of the multi-level requirement with the economic dispatch of electricity.

Response: EPA's analysis shows that numerous conditions may arise after siting, installation, and certification of a flow monitor to change a flow profile. These include: in-leakages or out-leakages in ducts or stacks, complete or partial disintegration of dampers or straightening vanes, stack or duct blockages due to caking, and changes in fan performance. These changes can occur without necessarily triggering recertification, yet can affect flow monitor performance. The EPA believes that only the annual 3-level audit can determine whether monitor performance has been significantly adversely affected by such changes since certification.

While EPA expects that the cost of 3-level relative accuracy tests will be somewhat higher than a 1-level test, the marginal cost of performing the two additional RATAs should be modest if all three tests are performed consecutively. This will ensure that two major costs will remain one-time expenditures for all three RATAs: the cost to transport the test team to the site and the cost of setting up and breaking down the test equipment. Annual RATA tests can be planned months in advance and scheduled to integrate into economic electric dispatch. Thus, EPA anticipates that utilities should be able to maintain adequate electrical generation in the affected area during the 3-level testing through planned dispatching arrangements.

Based on this assessment, the final rule retains the annual 3-level flow monitor RATA requirement. However, it broadens and increases the flexibility in defining each of the 3 test levels and clarifies the RATA testing requirements for flow monitors installed on common stacks.

(3) RATA Frequency

The proposed rule specified quarterly, semiannual and/or annual RATA frequency, depending on whether the flow monitor performed a daily electronic drift test or a calibration error test and on the relative accuracy level achieved. Monitors that performed a daily drift test, instead of a daily calibration error test, and obtained relative accuracy results greater than 10 percent were required to perform quarterly RATAs.

(a) Quarterly RATAs. Some commenters stated that quarterly RATAs were unreasonable and excessive for any flow monitor that is checked daily. Other commenters favored the calibration error test over the electronic drift test, arguing that the calibration error test was more meaningful. One commenter recommended dropping the electronic drift test option entirely. Nevertheless, most commenters supported the proposal to reduce RATA frequency for flow monitors achieving superior relative accuracy and stated that the proposed reduced frequency reward system would provide an incentive to maintain and improve CEMS performance. In contrast, one commenter opposed reducing RATA frequency to less than quarterly and suggested an incentive-based system that would credit and debit allowances by indexing the relative accuracy standard to the best industry performers.

Response: After carefully considering the range of comments on RATA frequency and criticisms of the electronic drift test, EPA has decided to delete the proposed requirement of quarterly RATAs and the option of performing an electronic drift test in place of the calibration error test. At the same time, as discussed in section 4 below, the final rule expands the allowable procedures that can be followed in performing calibration tests on flow monitors. Field studies and equipment specifications show that all major flow monitor technologies should now be able to perform the calibration tests as specified in the final rule. The EPA believes that the elimination of the electronic drift test and the addition of expanded calibration test procedures should assure daily indication of proper operation of all flow monitors as intended in the proposed regulations. Therefore, because of the deletion of the less credible electronic drift test, which needed quarterly RATA frequency, EPA believes semi-annual RATA frequency is now sufficient.

EPA rejected the proposal to credit and debit allowances. Although the proposal has merit in encouraging better RATA performance, EPA believes it would be administratively complex and difficult to implement.

(b) Frequency incentive under low flow conditions. Other comments on RATA frequency pertained specifically to low flow situations. Commenters argued that under low flow conditions the RATA frequency incentive system was inapplicable because of technological limits on achievable accuracy when flow rates drop below 10 fps. The commenters proposed that under low flow conditions, regardless of the accuracy achieved, RATAs should be performed on the least frequent basis

required for that type of flow monitor, i.e., annually for those performing a calibration error test and semiannually for those performing an electronic drift test.

Response: EPA believes that the proposed reduced RATA frequency incentive system is practical at low flow rates because of the new low flow accuracy standard of ±2 fps, described above. Consequently, EPA is extending the RATA frequency incentive system to low flow rate conditions. Under such conditions, flow monitors will qualify for reduced RATA frequency when the flow monitor mean is within ±1.5 fps of the reference method mean. Thus, if a flow monitor meets this standard and corresponding incentive thresholds on the other levels of the 3-level RATA, it may perform its next RATA in 12 months rather than six months. Manufacturer specifications for many flow monitors indicate that they are capable of meeting the 1.5 fps standard.

EPA believes that extending the incentive system to low flow conditions will provide the same incentive for improved accuracy under low flow conditions as under normal flow conditions. It should also reduce the required frequency, and hence the cost, of performing RATAs.

(4) Level Playing Field

At the time the proposed rule was drafted only ultrasonic flow monitors were known to be performing calibration error tests on the entire flow monitoring system— from sampling point through and including the data acquisition and handling system. Thus, in the proposed regulations, only ultrasonic monitors were required to perform the calibration error test, while non-ultrasonic monitors could either perform this test or conduct an electronic drift test. However, if they chose the latter, which only checks the stability of the monitor's electronics, not the full system, they were required to perform more frequent RATAs. In addition, the preamble requested comments on a proposal for a modified calibration test procedure for differential pressure monitors, which would be allowed to test from a point outside the stack, rather than from the probe tip, through the data acquisition and handling system.

The proposed flow monitor calibration error test was seen as discriminatory by several commenters, particularly vendors of thermal and differential pressure flow monitors. These vendors stated that the proposed requirements were detrimental to their competitive positions and could drive them out of the market unless the calibration error test were changed. Several ultrasonic and thermal flow monitor vendors supported the calibration error test as proposed. Differential pressure flow monitor vendors supported the modified calibration error test procedure, performed from a point outside the stack, rather than from the probe tip, provided that the probe is regularly backpurged.

Response: The final rule delineates two acceptable procedures that can be used in performing the calibration error test on any flow monitor: (1) A system check from and including the transducer/transceiver through and including the data acquisition and handling system in combination with daily or more frequent backpurge/probe/transceiver cleaning, or (2) a full system test from and including the sampling point, through and including the data acquisition and handling system. Whichever of these procedures is employed, all monitors are also required to perform an interference check no less frequently than every 24 hours. The interference check is a means to detect and correct plugging, fouling, and malfunctions that could interfere with the calibration test. Field studies and equipment specifications show that each of the three main types of flow monitors (thermal, differential pressure, and ultrasonic) are capable of performing the calibration error test, promulgated in today's rule.

(5) Orientation Sensitivity Test

To ensure that flow monitors would be properly oriented in the gas stream, the proposed regulations included an orientation sensitivity test. Several commenters stated that the orientation sensitivity test was unnecessary and difficult to perform for multi-port or array-type systems. These commenters also suggested that the periodic RATA would detect flow monitor orientation problems.

Response: EPA agrees with the commenters that proper orientation of a flow monitor would be ensured by periodic RATAs. Performing an orientation sensitivity test on installed multi-port or array-type flow monitors may be problematic because of the size and complexity of the installation. Out of these considerations, the orientation sensitivity test requirement has been deleted from the final rule.

(6) Instrument Span

Commenters urged EPA to delete or modify the proposed requirement that the span of the flow monitor be set so that average measured monthly volumetric flow fell between 40–75 percent of span. They maintained that the proposed span requirement might not serve the purpose of ensuring more accurate measurements at the predominant flow rates, because a unit might spend half its time at full load (e.g., during the day) and half of its time at low load (e.g., at night) and thereby meet the monthly average 40–75 percent requirement, while rarely ever actually measuring at 40–75 percent of span. One commenter suggested that EPA change the span requirement to an annual average.

Response: EPA agrees that diurnal changes in load and flow rates commonly occur, making it possible for a flow monitor to meet the proposed monthly average 40–75 percent of span requirement, but only infrequently actually measure flow rates at 40–75 percent of span. The purpose of the proposed span requirement was to (a) ensure that flow monitors would measure the predominant flow rates in the middle third of the monitor's span, (b) minimize full-scale exceedances, and (c) prevent artificially high spans that might diminish the monitor's accuracy at low flow rates.

To meet these goals and, at the same time, be responsive to public comment, the final rule drops the proposed requirement that average monthly volumetric flow fall within 40–75 percent of span. Instead, the final rule defines a "maximum potential flow" value, which is derived from the cross sectional area of the stack or duct where the monitor is located, the maximum heat input of all units feeding into that stack or duct, and the amount of combustion air. This value equals the maximum flow possible for a given stack or duct configuration, assuming all units feeding into the stack or duct are operating at their maximum heat input. The 7-day calibration error test, performed at initial certification, and the daily calibration error test calibrate the monitor on reference values set at 0–20 percent and 50–70 percent of the span. In addition, the final rule requires the span of a flow monitor to be set at 125 percent of the maximum potential flow value. This requirement should prevent full-scale exceedances.

E. Alternative Monitoring Systems

Section 412(a) of the Clean Air Act Amendments of 1990 requires that alternative monitoring systems provide information with "the same precision, reliability, accessibility, and timeliness as that provided by CEMS." The proposed regulations designated certified CEMS as the benchmark for evaluating an alternative's performance. Thus, to demonstrate equivalent

precision, an alternative was required to pass three statistical tests evaluating the CEMS and alternative method in terms of their respective systematic error, random error, and correlation. To meet the reliability criterion, the alternative was required to match a certified CEMS in terms of annual availability and ability to achieve performance specifications and quality assurance requirements. Finally, to meet the accessibility and timeliness criteria, an alternative had to match the CEMS' ability to record requisite emissions data on an hourly basis and report results within 24 hours.

(1) Overview

There were three major lines of comments on the alternative monitoring system requirements. One commenter strongly supported the proposed requirements for alternative monitoring systems as a way to ensure strict adherence to requirements of the Clean Air Act Amendments. Another commenter thought the requirements needed to be strengthened by not only stipulating that alternative monitoring systems provide information equivalent to CEMS, but also that the alternatives meet the same certification and performance test requirements as a CEMS (e.g., in terms of relative accuracy). A third set of commenters criticized the applicability of the statistical tests for precision, the stringency of these tests, the requirement that the alternative be compared to a CEMS, and the timeliness requirement. Another commenter objected to subjecting an alternative monitoring procedure to all of the Appendix B "Quality Assurance and Quality Control Procedures," noting that "meeting this criterion may be impossible."

Response: EPA agrees with the first commenter's position and notes that the second commenter's concerns were accommodated in the proposed regulations. An approved alternative monitoring would be subject to all the relevant Part 75 requirements as a CEMS, including initial certification and periodic performance testing requirements. As stated in the proposed regulations, alternative monitoring systems must satisfy all "the applicable requirements of appendix B" unless the owner or operator can demonstrate to the agency's satisfaction that meeting the requirements is physically or technologically impossible and can document equivalent or superior performance on comparable quality assurance and quality control performance standards. The agency believes that these provisions will ensure equivalency with a certified CEMS while leaving room for new technologies that may employ innovative monitoring methods.

The remainder of this section on alternative monitoring systems presents the agency's response to the concerns raised by the third group of commenters.

(2) Applicability of Statistical Tests

Some commenters argued that the three proposed statistical tests for precision were often inappropriate, because they depended on statistical assumptions that were often not met, namely, that the data are normally distributed and independent over time.

(a) Normality assumption. One commenter cited several studies that found emissions data to be lognormally distributed rather than normally distributed and to exhibit time dependency (also called autocorrelation). To support their argument, the commenter presented 22 paired hourly data points obtained simultaneously at the same monitoring location by two separate test teams, using EPA designated Reference Method 6 for measuring SO_2 concentration. The commenters' analysis found that the data did not support the assumptions of normality and statistical independence.

Response: The EPA's own statistical analysis, conducted to evaluate these comments, contradicts the claim that emissions data are frequently not normally distributed. To evaluate normality, EPA applied two standard tests (Shapiro-Wilk test and Kolmogorov test) in conjunction with visual inspections of Quantile-Quantile plots and histograms of the data. These were applied to the commenter's two data sets and 13 other emissions data sets, containing from 62 to 16,081 data points. All the data sets, except the data from the commenter's Test Team B, were found to be normally distributed as evidenced by their yielding extreme values of the test statistics, unimodal symmetric histograms, and straight diagonal Quantile-Quantile plots.

The disparity in the distributional form of Test Team A's and B's data may indicate a problem in one or both team's implementation of Method 6. Two test teams carrying out exactly the same reference method procedure concurrently at the same location will obtain different measurement values, but they should not obtain data with different distributions, unless the testing procedure was inconsistently applied or some other unrecognized problem occurred.

While EPA's analysis does not support the commenter's contention about the distributional form of emissions data, the regulations have nevertheless been modified to accommodate the possible situation, highlighted by the commenter, where emissions data are lognormally distributed. If such a case does arise, the regulations now allow using a logarithmic transformation to normalize the data before the three statistical tests are applied.

(b) Independence assumption. The commenter also notes that the validity of the statistical tests that are applied to alternative monitoring systems depends on the data being statistically independent over time. The commenter maintains that the assumption of independence is often violated.

Response: EPA finds that the commenter's point merits attention. When data are not independent over time, its variance tends to be understated by standard statistical procedures. An underestimated variance could distort the results obtained on some of the proposed statistical tests. An accepted and theoretically substantiated way to compensate for variance underestimation is to multiply the variance by an inflation factor derived from an autocorrelation analysis of the data. This autocorrelation-adjusted variance is then used in statistical tests that are premised on data independence. The EPA has augmented the statistical tests for alternative monitoring systems with a procedure for computing the variance inflation factor. The final rule identifies the conditions under which the factor would be applied.

(3) Stringency of Statistical Tests

Besides maintaining that the statistical tests were inappropriate, the commenter also argued that they were so stringent that "no alternative monitoring system will likely ever be certified." This claim rests mainly on two arguments.

(a) Argument 1: Two reference methods fail the test. The commenter applied the three proposed statistical tests to the paired data from the concurrently run Reference Methods 6 discussed above. The side-by-side reference methods failed the tests, leading the commenter to conclude that "If two identical, concurrently run Reference Methods * * * cannot pass the alternatives testing, it is highly unlikely that any alternative system evaluated against a Reference Method (or certified monitor) would ever pass."

Response: EPA discounts the credibility of the commenter's analysis, because the underlying data are suspect and the sample size too limited. As

noted earlier, concurrent measurements by two duplicate reference methods at the same test location should not produce data with different statistical distributions: Test Team A's data was normally distributed, while Test Team B's was non-normal. This disparity suggests a flaw in one or both of the test team's implementation of the reference method. Drawing conclusions from such data are questionable, particularly when the conclusions are premised on statistical procedures that require the two data sets to be normally distributed. In addition, EPA believes that the sample size of 22 points is too small to support the commenter's conclusion.

(b) Argument 2: The bias test is so sensitive to "incredibly small" measurement differences between two data sets that it is impossible to pass the t-test. The commenter maintains that the t-test is not practically useful because it detects statistically significant differences that are not practically significant.

Response: EPA believes that inconsistencies in the underlying premises render this argument unconvincing. On the one hand, the commenter asserts that the t-test cannot be applied to the cited Reference Method 6 data, because the paired differences are not normally distributed. Then, ignoring this very stricture, the commenter assumes normality and extrapolates the t-test results from the cited 22 hours of data to 720 hours of hypothesized data, concluding that a mere 2 ppm measurement difference would have caused failure on the t-test at the larger sample size. If absence of normality made it inappropriate to apply the t-test to the 22 hours of actual data, as the commenter claims, then extrapolating these t-test results to 720 hours of hypothetical data seems even more questionable.

To further evaluate the commenter's concerns about the stringency of the alternative monitoring statistical tests, EPA analyzed 30–60 days of hourly field test data from four CEMS installed on a common duct at a coal-fired utility that was assessing various brands of monitors as part of their procurement process. While the CEMS were not certified and this was not a controlled experiment that ensured uniformity in the operation of the four CEMS, the data was adequate to assess the stringency of the three alternative monitoring system statistical tests in a situation where no deliberate attempt was being made to meet the test criteria. Forty-one separate data subsets, containing 30 or more successive days of paired hourly CEMS–CEMS measurements were extracted from the field data. Of these, 26 passed the bias test and 20 passed all three statistical tests simultaneously. Had this been a controlled experiment, it could be expected that the pass rate would have been even higher. In any case, the analysis demonstrates that the three tests are not impossibly stringent, as the commenter claims.

While EPA's analysis does not corroborate the commenter's claim that the proposed standards are unattainable, the data screening and adjustment procedures, discussed in the preceding section should ensure that the statistical tests are fully applicable even when the data are not independent over time. Together with the issues discussed above, these additions to the final rule should address the commenter's concerns about the achievability of the alternative monitoring system requirements. Moreover, EPA believes that by clearly articulating the standards that will be used in evaluating proposed alternatives and by basing these standards on objective and widely accepted statistical tests, the proposed alternative monitoring system requirements should reduce the uncertainty that might otherwise impede technological development.

(4) Testing Against a Reference Method Instead of a CEMS

Several commenters objected to having to install a certified CEMS in order to perform the tests needed to gain approval for an alternative method. They pointed out that there were sites where an alternative was being requested because it was not possible to install a CEMS. They proposed that alternative methods be certified by testing them against EPA Reference Methods.

Response: The Clean Air Act Amendments specifically stipulate that alternative monitoring systems provide information with the same precision, reliability, accessibility, and timeliness as that provided by CEMS. The EPA interprets this as requiring comparison to an actual CEMS. Nevertheless, since the CEMS must be certified prior to and during operation by comparison to the Reference Method, EPA agrees with the commenters that a reference method may be used whenever they are operated to provide the same hourly data that would form the basis of the CEMS to alternative comparison on which the criteria are based. Specifically, the reference method would have to produce 720 hourly emission rates. However, many EPA approved reference methods, like the manual wet chemistry Method 6 for SO_2, are completely unsuitable for the round-the-clock testing required to demonstrate long-term operational equivalency to a CEMS. Often labor intensive, the reference methods were designed to provide a measurement standard for short-term performance tests like the Relative Accuracy Test Audit. EPA believes they are not practical for long-term equivalency testing. Nevertheless, today's final rule allows for the generation of the required hourly emission rate data through the use of reference method testing as well as an actual CEMS to be compared with an alternative monitoring system as specified in the rule.

(5) Timeliness Requirements

Arguing that it is "legally unnecessary and unreasonable as a practical matter," one commenter objected to defining timeliness as the ability to provide hourly data and issue a record of the data for the previous day within 24 hours.

Response: EPA disagrees with the commenter. The market-based regulatory process demands an unprecedented degree of accuracy in the emissions totals that are used to calculate allowances. The more aggregated the measurements, the less verification is possible, and the less will be the assurance of accurate allocation of allowances. Both CEMS and approved alternative monitoring systems must be able to provide data in hourly increments and report data within 24 hours if the Acid Rain Program is to implement effective quality assurance and control procedures, validate emissions data, and correct problems before the end of year allowance/emissions reconciliation. The timeliness requirements are also necessary for the proper functioning of the missing data procedure, which depends on hourly values to ensure that substituted values are derived from verifiable, quality assured historical data. EPA believes that the requirements are practically justified and technologically feasible, as discussed above. In addition, the requirements are not unduly burdensome for the regulated community, being equivalent to those mandated by the Clean Air Act Amendments for CEMS.

F. Missing Data Procedure

Section 412(d) of the Clean Air Act requires EPA to prescribe a method for calculating emissions when valid data are not being supplied by a unit's continuous emissions monitoring system (CEMS) or by an approved alternative monitoring system. To meet this requirement, the proposed regulations established a missing data

substitution procedure, designed to achieve five major goals:

- To encourage the use of CEMS as the primary method for determining emissions and, at the same time, foster effective operations and maintenance programs by putting in place strong incentives for minimizing monitor downtime and maximizing data capture rates.
- To replace missing values with modest estimates when monitor availability has been good and missing data periods have been short.
- To replace missing values with more conservative estimates when monitor availability has been poor and missing data periods have been long.
- To establish a procedure that is automatic in its execution, relying only on the CEMS-generated emissions database, thereby minimizing the need for enforcement actions and supporting the smooth and unambiguous operation of the program.
- To establish a procedure that is readily implementable by all affected units and not administratively burdensome for units or EPA.

The missing data procedure, established to achieve these goals, is a multi-tiered computational routine for deriving a substitution value from the values previously recorded by the monitor. The procedure is based on the premise that the longer the gap in recorded data and/or the lower the annual monitor availability, the more conservative the value to be substituted. In concert, two trigger conditions determine the conservativeness of the substituted value. The first trigger condition is annualized availability, i.e., the percentage of the immediately preceding 8760 unit operating hours in which valid, quality assured data was obtained. (Note that for the purposes of the missing data procedure, there are 8760 hours in a year, 2160 hours in a quarter, and 720 hours in a month.) The annualized availability determines the calculation tier that applies: Monitors whose annualized availability has been good (i.e., 95 percent or better) would employ the calculation options on the top tier where the resulting substitution values are likely to be least conservative. On the other hand, monitors whose annualized availability has been poor (i.e., below 90 percent) would use the calculation options on the lowest tier where the resulting substitution values would be most conservative.

Within each of these tiers, the second trigger condition, the length of the current outage, determines the elements of the calculation routine that will be combined to derive the substitution value. The calculation routine consists of three elements: A calculation method, e.g., average, percentile, or maximum value; a lookback period, e.g., the preceding 720 monitor operating hours or the hour before and the hour after the outage; and an indicator, known as a "bin," of whether the substituted value will be chosen from a pre-defined subset or from all of the values that were recorded during the lookback period. Longer outages trigger combinations of calculation elements that are likely to yield conservative substitution values to ensure that actual emissions will not be underestimated. Thus, a short outage (e.g., 4 hours) might trigger a calculation routine employing the average (method) of the monitored values in the hour before and hour after the outage (lookback), using all the recorded data (i.e., no bins are used). On the other hand, a long outage (e.g., 30 hours) might trigger the maximum (method) of the monitored values in the preceding 720 hours (lookback) for the subset of the previously recorded values falling within the same load range as occurred when the monitor was "down" (i.e., bins are employed).

Tables 1 and 2 summarize the missing data procedure for SO_2, NO_x, and flow as modified in the final rule. The crossed out entries in these tables show elements of the proposed procedure that were changed in response to public comments that EPA received. For example, Table 1 shows that the proposed sulfur content bins have been deleted from the missing data procedure for SO_2 CEMS in response to many comments indicating that the requirement would be very burdensome on affected units. It may be helpful to refer to these tables when reading the following detailed discussion of the public comments and the changes produced in response to them.

EPA received more than 400 comments on various aspects of the proposed missing data procedure. To help evaluate these comments and verify earlier analyses, EPA developed a sophisticated computer simulation model for testing the likely impact of variations of the trigger conditions and calculation routines in the missing data procedure. The model was applied to historic SO_2 and NO_x emissions data from units both with and without emissions controls. Each individual data set contained approximately 10,000 hourly emissions measurements. Sensitivity analysis was performed using both "worst case" and "most likely" scenarios for outage occurrences.

(Note: EPA has requested that Table 1 be printed as shown below. Crossed out entries in this table represent items, originally in the proposed regulations, that were changed in the final version of the regulations.)

TABLE 1.—MISSING DATA PROCEDURE FOR SO_2 CEMS

Trigger conditions		Calculation routines		
Annualized availability (percent)	Duration (N) of outage (hours)	Method	Lookback period	Bins[1]?
95% or more	N≤24	Average	HB/HA	~~No~~.
	N>24	Max of Average	HB/HA	~~No~~.
		Max of 90th percentile	720 operating hours	~~Yes~~.
				No.
90% or more, but below 95%	~~N≤6~~ 8	Average	HB/HA	~~No~~.
	~~6<N≤24~~	Max of ~~Average~~	~~HB/HA~~	~~No~~.
		~~Max of 90th percentile~~	~~720 operating hours~~	~~Yes~~.
	~~N>24~~ 8	Max of Average	HB/HA	~~No~~.
		Max of ~~90th~~ 95th percentile	~~8760~~ 720 operating hours	~~Yes~~.
				No.
Below 90%	N>0	~~Max of Average~~	~~HB/HA~~	~~No~~.
		~~Max of 90th percentile~~ Maximum[2].	~~8760~~ 720 operating hours	~~Yes~~.
				No.

HB/HA=hour before and hour after the outage.

[1] For SO_2 CEMS, the bins were defined on sulfur content ranges.

[2] Where unit with add-on emission controls can demonstrate that the controls are operating properly, as provided in §75.34, the unit may, upon approval, use the maximum controlled emission rate from the previous 720 operating hours.

(Note: EPA has requested that Table 2 be printed as shown below. Crossed out entries in this table represent items, originally in the proposed regulations, that were changed in the final version of the regulations.)

TABLE 2.—MISSING DATA PROCEDURE FOR NO_x and Flow CEMS

Trigger conditions		Calculation routines		
Annualized availability (percent)	Duration (N) of outage (hours)	Method	Lookback period	Bins [1] 7
95% or more	N≤24	Average	~~HB/HA~~ 2160 operating hours	Yes.
	N>24	Max of Average	HB/HA	No.
		Max of 90th percentile	~~720~~ 2160 operating hours	Yes.
90% or more, but below 95%	~~N≤8~~ 8	Average	~~HB/HA~~ 2160 operating hours	~~No.~~ Yes.
	~~8<N≤24~~	~~Max of Average~~	~~HB/HA~~	~~No.~~
		Max of ~~90th percentile~~	~~720 operating hours~~	~~Yes.~~
	N>~~24~~ 8	Max of Average	HB/HA	No.
		Max of ~~90th~~ 95th percentile	~~8760~~ 2160 operating hours	Yes.
Below 90%	N>0	~~Max of Average~~	~~HB/HA~~	~~No.~~
		Max of ~~90th percentile~~ Maximum.	~~8760~~ 2160 operating hours	Yes.

HB/HA=hour before and hour after the outage.

[1] For NO_x and Flow CEMS, the bins were defined on load ranges.

The major issues, raised by commenters and analyzed by EPA, were the following:

(1) Underlying Concepts

In general, commenters supported the basic underlying concept, on the one hand, of substituting an *interpolated* value derived from the average of the hour before and hour after when outages were short and annualized availability was above some threshold and, on the other hand, substituting a more conservative *historical* value when outages were longer or annualized availability dropped below some threshold. It should be noted, however, EPA does not agree with those commenters who seem to view interpolated values, like the average of the hour before and the hour after, as comparable to CEMS data. Interpolated values provide a satisfactory substitute for CEMS data only when outages are relatively short in duration and infrequent in occurrence. More extensive use of interpolated values increases the likelihood of incorrectly estimating emissions for individual monitors. To function effectively, the allowance trading component of the Acid Rain Program requires a complete and accurate accounting of emissions. It cannot rely on interpolated values for such an accounting. The EPA believes that high monitor availability, made possible by a missing data procedure that discourages outages, is the only effective guarantee that emissions will not be underestimated, as required by section 412(d) of the Clean Air Act.

(2) Trigger Conditions

(a) Annualized availability. A number of commenters expressed concern about the ability of CEMS to attain availabilities of 95 percent or more, particularly with monitors that would have to be retrofitted to meet the requirements of the Acid Rain Program. It was asserted that unsatisfactory results were experienced in Pennsylvania, where the average annualized availability for monitors retrofitted to meet the requirements of the State Implementation Plan was below 95 percent in the early phase of the program.

Response: A study of 186 retrofitted monitors during 1988–90 did not lend support to the commenters' concern. The study showed that approximately 75 percent of monitors at existing units, including units that will be covered under Phase I of the Acid Rain Program, have consistently attained availabilities above 95 percent. In addition, the most recent data on CEMS availability, obtained from the Commonwealth of Pennsylvania, indicates that, on average, annualized availability was 96 percent. This leads EPA to conclude that 95 percent availability is readily achievable, even by retrofitted monitors that are required to meet strict quality assurance and data validation standards in order to qualify as "available". It is also important to note that a monitor could be inoperative for a full 18 days each year and still have an annualized availability of more than 95 percent. The EPA believes that 18 days is more than enough time to accommodate both routine and unexpected outages for a properly maintained and operated CEMS.

Another commenter proposed indexing the top tier annualized availability trigger to the performance of the best monitors. It was argued that this would create an incentive for continuing improvement in monitor availability across the whole regulated community.

Response: While EPA encourages continuing improvement in availability, the agency believes the indexing approach might introduce an element of uncertainty into the emissions monitoring program that could be reflected, in turn, in the allowance market. The indexing approach would also present serious administrative difficulties both for EPA and sources. Therefore, EPA rejected this proposal.

Still another commenter argued that the bottom tier should be deleted and the second tier's trigger conditions and calculation routines should apply when annualized availability drops below 95 percent.

Response: EPA did not accept this proposal for several reasons. First, it would encourage the proliferation of short outages (6 hours or less, using the structure in the proposed missing data procedure), because values derived using the average of the hour before and the hour after an outage could be substituted for these short outages no matter how low the monitors annualized availability dropped. This would reduce confidence in the monitor's emissions accounting. Furthermore, the proposed change would remove virtually all incentives to repair a monitor with poor annualized availability. Accordingly, the Agency did not accept this commenter's proposal, instead preserving the

proposed separate lower tier, which is triggered by annualized availabilities below 90 percent and where conservative values are always substituted for missing data.

In summary, the final rule retains the three-tier structure of the earlier proposal, with the top tier still triggered by annualized availabilities 95 percent or better, and the bottom tier triggered by annualized availabilities below 90 percent.

(b) Duration of outages. Commenters made several proposals for modifying the length of outages that trigger various calculation routines. A number of commenters argued that the most conservative calculation routines should not be triggered by outages exceeding 24 hours but by outages exceeding 48 hours. The commenters maintained that a 48-hour trigger condition would provide a more reasonable length of time to repair monitors rendered inoperative by freak events beyond the operator's control.

Response: EPA rejected this proposal on three grounds. First, moving to a 48-hour trigger condition would remove an important incentive for quickly repairing monitors, even when the cause of the failure is easily fixed. Second, the commenters' proposal would mean that the calculation method based on averaging measurements taken the hour before and the hour after an outage would be used for outages as long as 48 hours. Using the hour before and the hour after approach on such long periods of missing data are likely to produce appreciable underestimations of emissions. Third, the argument for changing the trigger condition cutoff to 48 hours to allow more time for repairs was based on anecdotal evidence of repairs requiring more than 24 hours and did not convincingly demonstrate that 24 hours was insufficient for most repairs. The commenter's rationale could just as easily have been used for lengthening the cutoff to any duration longer than 24 hours.

Many commenters requested that the average hour-before/hour-after calculation procedure apply for outages longer than 6 hours when annualized availabilities ranged from 90 percent up to 95 percent (i.e., on the middle availability tier). Some proposed moving the trigger condition up to 8 hours; others proposed 12 and 24 hours. They argued that more repairs could be completed in 8, 12, or 24 hours than in 6.

Response: After weighing the possibility that extending the use of the average of the hour before and the hour after might reduce the incentive for quick repairs and increase the variability of substitution values produced by the missing data procedure, the agency has decided to adopt the proposal to extend the trigger condition from 6 to 8 hours in the final rule. The EPA believes that this change should allow more time for monitor repairs without significantly impairing the accuracy and consistency of emissions accounting. Along with this modification, only one trigger condition ($N>8$) will now apply to outages longer than 8 hours in the middle availability tier, whereas two trigger conditions ($6<N\leq24$ and $N>24$) applied to outages longer than 6 hours in the original proposed regulations. Together, these modifications simplify and support a truly graduated system of increasing incentives for improvements in annualized availability.

(3) Calculation Routines

(a) Calculation method. Commenters expressed strong views on the appropriate calculation method to employ in the missing data procedure. A diverse array of commenters argued that only by substituting the maximum previously recorded value could EPA effectively meet the requirement in section 412(d) of the Clean Air Act, stipulating that a unit should be considered as operating "in an uncontrolled manner" during periods when "the owner or operator cannot provide information, satisfactory to the Administrator, on emissions during that period." These commenters considered the maximum value as the only effective deterrent to deliberate shutdowns of CEMS during periods of high emissions.

Many commenters supported using a percentile of previously recorded values to calculate substitution values. Most thought the 90th percentile provided an adequate incentive for high CEMS availability without producing an undue overestimation of emissions and a concomitant inappropriate loss of allowances. Some proposed using the 70th percentile when annualized availability exceeded 90 percent.

The proposed rule requested comment on the advisability of using the average of the five highest previously recorded values as a calculation method. Almost all commenters rejected this proposal.

Response: EPA has incorporated into the revised missing data procedure calculation methods that it believes reflect a reasonable compromise of the extremes proposed by the commenters. The final rule contains a balanced, graduated approach with the substitution of progressively more conservative values for periods of missing data. Those monitors attaining the target annualized availability of 95 percent or better will substitute the 90th percentile value during outages exceeding 24 hours. Monitors whose annualized availability falls in the middle tier (from 90 percent up to 95 percent) will substitute the slightly higher 95th percentile value during outages exceeding 8 hours. Finally, monitors whose poor annualized availabilities place them on the third tier (below 90 percent annualized availability) will substitute the maximum recorded value for any outage. This should provide a substantial incentive to improve monitor availability. Combined with the use of uniform and shortened lookback periods, described below, this graduated approach will result in a more consistent incentive to maintain high operating availabilities than the proposed procedures.

(b) Lookback period. In the proposed rule, percentile calculations were performed on either 30 or 365 operating days of previously recorded data. Commenters objected to the 365-day lookback period, particularly for SO_2 concentration CEMS. They were concerned that a unit that reduced its SO_2 emissions could still be "stuck" with outdated high substitution values for a full year. This could prove particularly troublesome in the initial year of allowance accounting when substituted values might be derived from periods prior to the required implementation of SO_2 emissions reductions.

Response: The final rule drops the 365-day lookback period and adopts a 30-day lookback (i.e., 720 monitor operating hours) for all percentile and maximum value calculations employed in the missing data procedure for SO_2 CEMS. Moving to a single 30-day lookback addresses the commenters' concerns without reducing the incentive for increased monitor availability. One commenter noted and EPA's analysis indicates that the 90th percentile of 365 days of data did not yield consistently higher substitution values than the 90th percentile of 30 days of data. Shortening the lookback period from 365 to 30 days also substantially reduces data storage requirements for the missing data procedure.

On the same grounds, a single 90-day lookback (i.e., 2160 monitor operating hours) will be employed for NO_x and flow CEMS, instead of the 30- and 365-day lookback periods originally proposed. A 90-day lookback, rather than a 30-day lookback, is required for NO_x and flow, in order to increase the likelihood that appropriate load "bins" will contain at least some previously

recorded CEMS values. As explained below, "bins" are retained in the missing data procedure for NO_x and flow CEMS, but dropped for SO_2 CEMS.

(c) Bins. Many commenters objected to the expense of the proposed requirement for fuel sampling and analysis, which were needed in order to use SO_2 bins in the missing data procedure. Other commenters noted that it is inappropriate to mix coal sampling and CEMS data because coal sampling data are less precise and reliable. Data provided by one utility showed a daily variability of −10 percent to +45 percent in the difference between the SO_2 values derived from coal sampling and the SO_2 CEMS measurements.

Response: Based on this data, EPA agrees that it is inappropriate to compare coal sulfur content with CEMS values, either by correlation with contemporaneous CEMS readings or by direct substitution. Therefore, the final rule drops the fuel sulfur "bins" requirement from the missing data procedure for SO_2 CEMS. That is, SO_2 concentration will not need to be correlated with fuel sulfur content when performing percentile calculations of SO_2 substitution values. An added benefit of removing the fuel sulfur bin requirement is that the cost of implementing the missing data procedure for SO_2 CEMS will be reduced substantially, because utilities will not be required to perform coal sampling and analysis in order to implement the missing data procedure.

The Agency also considered dropping the load "bins" requirement from the missing data procedures for NO_x and flow CEMS. However, many commenters supported the use of load ranges when calculating substitution values for NO_x and flow, arguing that this would produce more accurate substitution values. Commenters who opposed the NO_x/load or flow/load correlations, embodied in "bins," cited either the unnecessary complexity of correlating operating data and monitor data, or the more accurate correlations that could be obtained using regression analysis.

Response: Using a uniform 90-day lookback in the missing data procedure for NO_x and flow CEMS and a smaller number of uniformly sized bins should reduce the complexity noted by some commenters. Although the regression analysis could provide satisfactory correlations, the method would require site-by-site analysis of extensive amounts of flow and load data. EPA believes that this approach would impose too great an administrative burden both on the industry and EPA. Thus, EPA has decided to retain the load bins for NO_x and flow CEMS and adopt a uniform 90-day lookback period in the NO_x and flow missing data procedures.

(4) Other Missing Data Issues

(a) Definition of missing data. The Agency reiterates that data from a certified backup monitor or an approved alternative monitoring system is not considered to be "missing." When such methods are operating in accordance with the regulations, data are considered to be "available," as required under section 412(d) of the Act. Correspondingly, when quality assured hourly data are not available from the certified CEMS or from one of these methods, then the missing data procedure must be used.

(b) Alternative missing data procedures. Several commenters requested that an administrative mechanism be established to allow sources to employ alternative missing data procedures in place of those specified in the regulations.

Response: The proposed regulations included provisions that would allow units with emissions controls that are independent of the combustion process (e.g., scrubbers) to use parametric substitution methods for missing data, instead of the standard missing data procedure. However, this "alternative" procedure is applicable only under clearly prescribed circumstances: it was designed to address anomalies that could result if the standard missing data procedure were applied to one specific class of units, those with independent emissions controls. In this case, the standard missing data procedure could seriously overestimate emissions. If the CEMS failed to report an hourly value but the emissions control equipment was functioning properly, the standard missing data procedure could substitute an inappropriately high uncontrolled emissions value, seriously overestimating emissions. The option of using a parametric substitution method at these units provides a greater level of consistency in emissions accounting between controlled and uncontrolled units.

The final rule includes distinct missing data procedures for oil- and gas-fired peaking units that qualify for exceptions to the SO_2 CEMS requirements, as described in Appendix D of the regulations. These procedures are adaptations of the standard missing data procedure, tailored to the specific characteristics of the excepted monitoring method.

EPA does not consider alternative missing data procedures to be justified for types of units other than those discussed above. The EPA is particularly concerned that a multiplicity of alternative missing data procedures could seriously jeopardize the national consistency of emissions accounting.

(c) Maximum controlled emission rate. Several commenters requested that EPA allow an affected unit equipped with add-on emission controls to substitute something more reasonable than the maximum recorded value, which may have occurred when the add-on emission controls were not functioning properly, if the owner or operator can show that the add-on emission controls were in fact operating properly during the current monitor outage.

Response: EPA agrees, and has modified the final rule to allow for a petition to the Administrator; specifically, if the owner or operator can demonstrate that (1) the affected unit's monitor data availability is below 90% availability and (2) the add-on emission controls were operating properly for the time period (or data gap) during which the affected unit experienced the monitor outage that would result in the substitution of an uncontrolled maximum value under the standard missing data procedures, then the owner or operator may submit the list of the average hourly values for the previous 720 quality-assured monitor operating hours, highlighting both the maximum recorded value and the value corresponding to the maximum controlled emission rate. The Administrator will automatically approve the use of the maximum controlled emission rate, if the petition adequately demonstrates that all of these requirements have been met.

G. Calibration Testing

Comments on the proposed calibration testing requirements for pollutant concentration monitors touched upon four major issues: terminology, the definition of instrument span, test specifications, and test procedures. Calibration issues related to flow monitors were discussed in the section on flow monitors above.

(1) Terminology

In the proposed rule the term "calibration error test" was used to refer to three separate calibration testing requirements, i.e., those required daily, quarterly, and at initial certification. The use of a single name created confusion because the purposes and procedures of the tests differed. The EPA received many comments that lack of clarity in the terminology caused uncertainty about the intent, timing, and

procedures of the tests. Commenters also noted that the proposed 7-day calibration error test at initial certification was really a hybrid of two tests: (1) A linearity check to ensure that CEMS responses were within tight tolerances of the calibration gases and that deviations remained relatively linear over the entire measurement range; and (2) a drift test to detect and limit day-to-day drift in the calibration curve of the monitoring instrument and to keep the instrument within range of high- and zero-level calibration gases. Commenters suggested that not only were the hybrid requirements confusing, but that using the tight standards of a linearity check in a calibration drift test could render the hybrid test needlessly difficult to pass without achieving the implicit goals of the calibration procedure. It was also noted that the linearity component of the hybrid test was equivalent to the proposed quarterly 3-point calibration error test and the drift test component was equivalent to the proposed daily calibration error test.

Response: In the final rule the calibration procedure performed at initial certification is disaggregated into its two component tests: a linearity check performed for one day only and a 7-day calibration error test. The term "daily calibration error" test has not been changed in the final rule.

The linearity check is a 3-point test in which the permissible deviation of the CEMS response from the calibration gases is defined as a percent of the "tag" value of the gases. The "tag" value is the vender certified concentration specified on the label of a cylinder of calibration gas. What was referred to as the "quarterly calibration error test" in the proposed rule is now called a "quarterly linearity check" to indicate that it is the same test as the linearity check performed at initial certification.

The daily calibration error test, specified in today's regulations, is a 2-point drift test, comparable to the calibration drift test required under NSPS (40 CFR 60, Appendix B) except that it requires using Protocol 1 calibration gases. Unlike the daily calibration error test in the proposed regulations, the permissible day-to-day drift in the CEMS measurements is now defined as a percent of the span of the instrument rather than as a percent of the calibration gas value. The 7-day calibration error test performed during certification is the same 2-point drift test as the daily calibration error test.

(2) Instrument Span

The proposed regulations stipulated that the CEMS span should be set to ensure that the average concentration would fall between 40 and 75 percent of the span of the instrument. Whenever the monthly average emissions concentration fell outside these boundaries, the operator was required to adjust the span to bring it back into compliance. The regulations also stated that "full-scale exceedances shall not occur."

A majority of commenters stated that the 40–75 percent span requirement would be too difficult to maintain and that the proposed monthly adjustments of span were not practical. They suggested that the boundaries on monthly concentration be expanded from 40–75 percent to 10–90 percent or that the span requirement be completely redefined to be compatible with definition of span under subpart Da of the New Source Performance Standards (NSPS).

Response: EPA continues to believe that the best way to define span for the purposes of the Acid Rain Program is to base it on boundaries that ensure that the predominant monitor readings fall in the middle third of the span, as was done in the proposed rule. However, in light of many negative comments and in order to make the calibration procedures under the Acid Rain Program as compatible as possible with current practices under subpart Da of NSPS, EPA has modified the span requirements in the final rule.

Under the final rule, every unit is required to set the span of its SO_2 and NO_x pollutant concentration CEMS at 125 percent of the "maximum *potential* concentration." For SO_2 CEMS, a unit's maximum potential concentration is determined by the specific characteristics of the fuel that the unit is capable of burning. In particular, the maximum potential concentration is calculated from the maximum percentage sulfur content and the gross calorific value of the fuel, using a conversion factor that assumes complete combustion (see Equation 1.2.1.a in Appendix A to part 75). The monitor range defined on the maximum potential concentration is known as the "high-scale" of the monitor.

For SO_2 CEMS on units with emission control equipment, the monitor must not only be capable of meeting the above requirements, it must also be able to perform and pass the calibration tests using low, mid, and high calibration gases whose concentrations are defined by the unit's "maximum *expected* concentration." For these units, the "maximum *expected* concentration" is the maximum concentration that would occur if the unit's control equipment is operating at its fractional design removal efficiency. It is calculated by multiplying the maximum potential concentration by one minus the design removal efficiency. The monitor range is set at 125 percent of the maximum expected concentration and is known as the "low-scale" of the monitor.

The operator of any unit may also elect to establish "maximum expected concentration" levels in order to determine additional sets of low, mid, and high SO_2 calibration gas concentrations to be used in calibrating on spans other than the one defined on the "maximum potential concentration." This option should accommodate situations, identified by commenters, where the most prevalent emission concentrations fall into one or more discrete bands, not necessarily in the center of the span range established using the maximum potential concentration. This rule allows sources, under such circumstances, to employ multi-span monitors, each span being calibrated on its own set of calibration gases.

As in NSPS, the span of NO_x and diluent gas CEMS is explicitly specified in the final rule: For boilers without emissions controls, the maximum potential concentration for NO_x pollutant concentration is assigned a value of 1,600 ppm at coal-fired units and 480 ppm at oil-fired and gas-fired units. For boilers with emissions controls, the maximum expected concentration is assigned a value of 800 ppm at coal-fired units and 400 ppm at oil-fired and gas-fired units. For other units electing to set a low-scale for their NO_x pollutant concentration monitor, the maximum expected concentration is assigned a value of 320 ppm at coal-fired units and 160 ppm at oil-fired and gas-fired units. The span of the diluent gas monitor would be set at 25 percent O_2 or CO_2, as applicable. Based on NSPS experience, this approach to defining the span of NO_x and diluent gas CEMS is effective without being either restrictive or burdensome.

Operators at all units are required to perform the quarterly and initial certification linearity checks on the high-scale of their instruments. In addition, operators of units with emission controls and other units that choose to use additional spans must also perform the quarterly and initial linearity checks on the low-scale of their instruments. Finally, operators need only perform the daily calibration error test on the monitor ranges that were actually used for one hour or more since the previous daily calibration error test.

This new approach for defining the span of CEMS responds to commenters' concern that the earlier 40–75 percent

approach in the proposed regulations would inevitably lead to violations of the stricture that "full-scale exceedances shall not occur." The EPA believes that under the new requirement full-scale exceedances should not occur. At the same time, the agency encourages operators to set the span of their instruments, where practicable, so that the majority of readings occur within 25–75 percent of the instrument span.

The modified approach to defining the span of CEMS closely resembles that used in NSPS, although it cannot exactly coincide due to differing program standards and emissions characteristics of the regulated units. Coordination of the definitions of span should reduce needless disparities in requirements on units affected by both NSPS and the Acid Rain Program. It should also facilitate implementation, since CEMS operators will find the new requirements to be familiar.

At the same time, the new approach addresses the commenters' two major concerns regarding the originally proposed method for defining span. It eliminates the uncertainty engendered by basing span adjustments on the previous month's average emissions concentration, and it prevents full-scale exceedances.

(3) Performance Specifications

The proposed rule required that pollutant concentration monitors be calibrated to within a performance specification of ±2.5 percent of the gas concentration when measuring calibration gases whose concentration was above 250 ppm and to within a performance specification of the greater of ±5.0 percent or ±8 ppm when measuring calibration gases whose concentration was 250 ppm or lower. For diluent gas monitors the specification was set at ±0.5 percent of the calibration gas. In all three calibration tests—daily, quarterly, and initial certification—the specification applied to the monitor's measurement of a reference Protocol 1 gas. On the daily and quarterly calibration tests, the monitor would be considered "out of control" if the percentage deviation of the monitor measurement from the "tag" value of the calibration was more than twice the performance specification. However, on the initial certification test, if the percentage deviation simply exceeded the performance specification, the monitor would fail and have to repeat the 7-day calibration error test.

A majority of commenters stated that it would be practically impossible to meet the specifications when using low-level concentration gases having concentrations between zero and 20 percent of the instrument span. Commenters suggested that the specification should not be applied to the "tag" value of the calibration gas, but to the full span of the instrument.

Response: EPA is making two substantive modifications of the proposed regulations to respond to the commenters' concerns. First, the definitions of the low- and mid-level concentration gases used in the linearity checks performed during initial certification and quarterly thereafter have been changed in the final rule. The low-level concentration is now designated as 20–30 percent of span instead of 0–20 percent of span; mid-level will be 50–60 percent, not 40–60 percent; and high-level will remain at 80–100 percent. Separate sets of calibration gases are determined separately for the high- and low-scale of the monitor, based on their respective span values. The revised concentration ranges are consistent with requirements under NSPS, which defines the concentration levels in this manner. As a result of these modifications and the change in the definition of the span of the instrument, the low-level gas, which was of greatest concern to commenters, is likely to be of higher concentration than it would have been under the proposed requirements. Therefore, monitors will more easily meet the linearity check performance specifications at the low calibration gas concentration. In addition, if the CEMS response is within ±5 percent of the calibration gas value, the specification will be considered to be met.

Second, in the daily calibration error test, the specification for the SO_2 and NO_x pollutant concentration monitors will be applied to the span of the instrument and not the "tag value" of the calibration gas, as had originally been proposed. At both the zero-level (0–20 percent) and high-level (80–100 percent) calibration gas, the pollutant concentration monitor's response will be required not to deviate from the calibration gas by more than twice the specification times the span of the instrument. For SO_2 and NO_x CEMS this means that the monitor and the calibration gas must not differ by more than 5 percent of the instrument span (either the high-scale or low-scale span, as applicable). For diluent gas, the monitor response and the calibration gas must not differ by not more than 1 percent CO_2 or O_2. In Pennsylvania, where similar standards have been in place, the failure rate on comparable daily calibration tests over several years has been below 1.5 percent.

Though EPA is making these changes in response to comments, the agency is concerned that basing the calibration specification on the span of the instrument may allow a large and potentially detrimental margin of error when calibrating on zero-level concentration gases. Therefore, the agency will continue to analyze the daily calibration error test data obtained under the Acid Rain Program and evaluate the effectiveness of the calibration error test.

In the linearity checks, both at initial certification and during the quarterly calibration audits, the performance specification will continue to be applied to the calibration gas value. This approach is necessary to ensure the accuracy of the monitoring program and is consistent with standard practice for linearity tests. Data from periodic cylinder gas audits performed under NSPS and under Pennsylvania's State Implementation Plan indicate that the required performance specifications for linearity checks are attainable.

(4) Test Procedures

(a) For initial certification. As part of the initial certification requirements, the proposed rule required the calibration error test to be performed once a day for seven consecutive days with the unit operating at 50 percent or more of maximum load. Each day, a three-point test, using low-, mid-, and high-level gases, was to be performed with the monitor being challenged 3 times at each concentration. Comments on this test requirement focused on three main issues: Many commenters felt the requirement to operate at 50 percent or more of maximum load was unnecessarily burdensome and could force some units to operate above their planned dispatch levels. Others objected to having to challenge the monitor three times at each gas concentration, saying that so much time would be spent on calibration that the monitor's ability to measure actual emissions would be impaired. Still others thought that a 7-day, 3-point test was redundant and unnecessary.

Response: In agreement with the commenters' concerns, the final rule drops the load stipulation for the calibration tests performed at initial certification. However, the unit is required to be operating during the period of testing, because calibration of the instrument is affected by temperature, pressure, and moisture conditions of the sampled gas as encountered under actual operating conditions. The final rule retains the requirement to challenge a monitor three times at each concentration level.

Under the final regulations a 3-point linearity check must be performed only for one day during certification. In this test three gas concentrations are needed to ensure linearity over the range of monitor measurements. The 7-day test is now a 2-point calibration error test. It is the same as the daily calibration error test that will be performed once the certified monitor begins operation.

The EPA believes that comprehensive and thorough calibration testing at certification is particularly important, because it will allow detection and correction of problems before the monitor becomes operational under the Acid Rain Program. Meticulous testing at certification can pay large rewards over the life of the monitoring program, enabling units to eliminate problems early that would have been much more costly and disruptive to correct later.

(b) Quarterly assessment. The proposed regulations required a three-point calibration error test to be performed each calendar quarter. Using low, mid, and high concentration gases, the monitor would be challenged three times at each concentration. Dual range monitors would perform a separate 3-point test at each range. Commenters expressed some confusion about the purpose and requirements of this test.

Response: The final rule retains the quarterly assessment essentially as originally proposed. As noted above, to help clarify the nature and purpose of the quarterly assessment, its name has been changed to "linearity check" instead of "three-point calibration error test." The quarterly test is intended to serve as a periodic "spot check" to ensure that CEMS measurements do not deviate from the "tag" value of each of the three calibration gases by more than ±5.0 percent. In addition, as a linearity check, it will ensure that deviations from the calibration gas values are relatively uniform over the full measurement range of the monitor.

(c) Daily assessments. The proposed rule required calibration error tests to be performed at least once every 24 hours using a low and high concentration reference gas. When performing this test, the operator was to make no adjustments for low-level concentration measurements before completing the high-level calibration checks. Commenters expressed concern that this requirement would prevent an operator from correcting the drift at the high-level gas (known as span drift) by the drift measured at the zero-level gas (known as zero drift). Another major concern focused on the ability of a CEMS to meet a performance specification based on the "tag value" of the low concentration gas.

Response: This test remains as proposed, except that the performance specification will be applied to the span of the instrument instead of to the reference gas values, as discussed in detail above under "Performance Specifications." This change should address the concern about the achievability of the performance specification. The final regulations retain the restrictions on adjustments for drift. However, the agency notes that an operator may computationally correct span drift for zero-drift, but only after both zero- and span-drift have been documented. This is comparable to the requirements under Performance Specification 2 (40 CFR part 60, Appendix B).

Exceptions to CEMS Requirement

EPA received more than 1,000 comments on proposed exceptions to monitoring requirements for SO_2, NO_x, and opacity, as well as on a general exception to the Acid Rain Program's emission reduction, permitting, and monitoring requirements for clean, small new units.

(1) For SO_2 CEMS

In the proposed regulations, exceptions from the CEMS requirements for SO_2 were proposed for two categories of units: Oil-fired units, in general, and combined gas/oil-fired units that derived 90 percent or more of their heat input during the year from natural gas. In the following discussion, the latter units will be referred to as "90-percent gas-fired units."

The first exception would allow oil-fired units to monitor their oil flow rate using a fuel flow meter, analyze the sulfur content of either continuous drip or "flow proportional" samples of the oil, and, then, calculate hourly SO_2 emissions from the corresponding hourly flow rate and sulfur content measurements. "Flow proportional" sampling refers to an automated process whose frequency of sampling is not tied to the time elapsed but rather is proportional to the amount of fluid passing the monitoring location. For example, samples might be taken every ten barrels or every 100 gallons or every 50 pounds of fluid. Under this proposed exception, hourly SO_2 emissions had to be reported within 24 hours of their occurrence.

The exception for 90 percent gas-fired units was similar. However, these units were required only to take daily manual grab samples of the oil, calculate daily SO_2 emissions, and report results within 24 hours. By implication, units burning natural gas exclusively were completely exempted from the SO_2 CEMS requirements.

Some commenters supported the proposed SO_2 monitoring exceptions; some recommended a longer turnaround time for oil analysis; and some proposed a less frequent sampling requirement for oil-fired units. One organization opposed less frequent oil sampling. Others supported allowing a fuel flow meter combined with a diluent monitor to be used in place of a volumetric flow monitor.

Response: The two exceptions included in the proposed regulations are retained in the final rule. In addition, based on the public comments that were received and an analysis of SO_2 emissions data in the National Utility Reference File (NURF) emission inventory, EPA is extending the exception for 90 percent gas fired units to all oil-fired units and lengthening the required turnaround time for oil sample analysis under this exception from 24 hours to thirty days. No other changes to the originally proposed exceptions from SO_2 monitoring have been made. In general, the exceptions granted to gas- and oil-fired units were based on substantial evidence showing that the excepted monitoring methods performed extremely well for these types of fuels with respect to the statutory criteria for equivalency to CEMS, as specified in section 412(a) of the Act. EPA believes that these exceptions are within its discretion in administering the Act. *See Alabama Power Co.* v. *Costle,* 636 F. 2d 323,360–61 (D.C. Cir. 1979). Details of EPA's position are given below.

(a) Exception for oil-fired units. As noted in the preceding paragraph, today's rule provides an exception in Appendix D of Part 75 for monitoring SO_2 emissions at oil-fired units based on the performance of the excepted monitoring methods. The first excepted method relies on automatic fuel sampling, whose sampling frequency is proportional to the fuel flow, with a minimum of one sample drawn each hour. In addition, the "continuous" and flow-proportional oil samples are required to be aggregated and analyzed for sulfur content on a daily basis, using American Society for Testing and Materials (ASTM) standard laboratory procedures. Finally, the rule requires that oil flow meters be calibrated annually.

Since SO_2 emissions from this class of unit can be significant, the rules have designed the method to ensure accurate information, representative of each hour of unit operation, thus ensuring equivalence to CEMS. The method has three main features: accurate metering

of oil flow, as-fired oil sampling (i.e., actual fuel samples taken in proportion to fuel consumption as measured by the fuel flow meters), and accurate accepted procedures specified by ASTM for analyzing the sulfur content and density of the oil samples.

As is explained further below, the evidence available indicates that the oil sampling and analysis method compares favorably to the statutory criteria for "sameness" in section 412(a) of the Act: (1) It is as precise as CEMS; (2) it is no less reliable than CEMS; (3) the information generated from the method—calculations of actual hourly emissions based on representative samples and measurements—is as accessible and useful as that reported by CEMS; and (4) it compares acceptably to the CEMS requirements with regard to the timeliness of measurements and data verification. In short, the only relevant distinction between the CEMS requirements and the flow-proportion continuous oil sampling and analysis method approved today is the measurement method.

The following is an elaboration of EPA's response to two aspects of this exception that attracted specific public comments:

(i) Accuracy of fuel-flow metering. The final rule preserves the proposed fuel flow meter accuracy specification of ±2 percent. The EPA clarifies that this specification is ±2 percent of the maximum flow that can be measured by the meter, known as the "upper range value". Several commenters asked that EPA set a more relaxed accuracy limit. This proposal may have been prompted by confusion over whether the accuracy specification was to be applied to the actual flow or the upper range value. The EPA evaluated this request and decided not to alter the accuracy requirement, based on two considerations: First, information available to EPA indicates that the ±2 percent accuracy specification is achievable by commonly-used types of flow meters, including coriolis-type mass flow meters, positive displacement flow meters, and square-orifice differential-pressure flow meters, and some other less expensive flow meters. Second, the ±2 percent accuracy limit is necessary given the variations in accuracy inherent in the ASTM fuel sample analysis methods. Maintaining the ±2 percent accuracy limit is particularly important, because the final rule adds flexibility by allowing the use of numerous applicable ASTM analytical methods.

(ii) As-fired oil sampling. The CEMS requirements call for continuous measurements of emissions (i.e., hourly averages based on measurements taken at fifteen minute intervals with no fewer than 2 measurements in any hour) followed by data verification within 24 hours. The excepted method for oil-fired units requires automatic sampling on an hourly (or more frequent) basis in proportion to the rate of oil flow. In the oil fuel sampling and analysis method, fuel sample grabs are taken in proportion to the fuel used, with sample grabs required at least once each hour, and sample analyses required each day. This provides samples that are truly representative of each hour of unit operation. Thus, both methods result in measured hourly values.

Commenters suggested a number of ways that the frequency of oil sampling could be reduced, including procedures that account for changes in the sulfur content upon the arrival of each new oil delivery. EPA rejected these suggestions because they would have resulted in less frequent sampling, which would have increased the potential to underestimate the sulfur content of the oil combusted by this category of unit, and would not have assured that the reported emissions represented the actual emissions for the reported point in time.

(b) Exception for oil-fired and gas-fired units. The final rule retains the previously proposed excepted method for calculating SO_2 emissions at gas-fired units that burn natural gas for no less than 90 percent of their total heat input during the year and burn oil—including diesel oil—as their backup fuel for the remaining heat input. *See* 56 FR at 63089. In addition, as noted above, the final rule extends this exception as an option to oil-fired units. These units are not required to use this excepted method for SO_2 monitoring. Rather, they may install a CEMS or employ the continuous oil fuel sampling method described above and in appendix D of part 75.

(i) De minimis exemption from SO_2 monitoring when units burn 100 percent natural gas. Gas-fired units would only be required to monitor SO_2, when they are actually burning oil. This is appropriate due to the *de minimis* nature of the SO_2 emissions from refined natural gas fuel. See discussion of *de minimis* exceptions in the preamble to part 72, Permits. Specifically, units that exclusively use natural gas emit only a small amount of SO_2 each year. Based on the typical amount of sulfur found in natural gas, as measured by ASTM analysis methods, a typical exclusively gas-fired unit emits less than 100 kg of SO_2 annually while combusting natural gas. See discussion of *de minimis* exceptions in the preamble to part 72, Permits.

While emissions are also relatively small from gas-fired units that use oil, including diesel, as a back-up fuel for no more than 10 percent of their heat input, the emissions are not completely negligible. According to the National Allowances Database, there are 525 existing 90-percent gas-fired units. This category of unit emitted 7,600 tons of SO_2 in 1985, yielding per unit average emissions of less than 15 tons annually. Six of the 525 units emitted more than 100 tons in 1985, the cut-off under title V of the Act for "major" sources. Thus, the final regulations stipulate that when a 90-percent gas-fired unit combusts oil, it is required to use an in-line oil flow meter to continuously monitor the amount of oil consumed and to use the highest sulfur value from a series of daily fuel samples in calculating the SO_2 mass emissions in units of pounds per hour.

(ii) Comparison of the excepted method to CEMS. As with the excepted continuous fuel sampling method, this exception for 90 percent gas-fired and oil-fired units compares well to CEMS with regard to precision, reliability, and accessibility. The method differs from the flow-proportional "continuous" oil fuel sampling method—and thus from CEMS—only with regard to the measurement method. As was discussed above, the CEMS and the flow-proportional continuous oil fuel sampling method call for continuous measurements of emissions. In contrast, the alternate excepted method for 90 percent gas-fired and oil-fired units requires daily manual oil samples. Furthermore, SO_2 emissions are required to be calculated using the highest measured fuel sulfur content recorded in the previous 30 daily samples.

EPA believes that differences between this method and CEMS with regard to measurement and verification frequency are not critical to the exception's methodology. Specifically, as discussed in greater detail below, the measurement frequency, applicable to CEMS, is not needed in the case of gas-fired units and oil-fired units in order to generate representative calculations of a unit's actual SO_2 emissions on an hour by hour basis.

Measurement frequency. EPA considered several factors in concluding that the specified measurement frequency is sufficiently timely for gas-fired units and oil-fired units. First, due to the homogeneity of this particular fuel source, the sulfur content of the daily oil-fuel supply used by these categories of units is unlikely to vary

significantly during a day. Oil fuel typically has a highly homogeneous sulfur content as compared to coal and coal-derived fuels. Moreover, even day-to-day variation in sulfur content will be very limited, since the two source categories which will use this method typically purchase and consume batches of oil fuel infrequently. In addition, fuel usage at gas- and oil-fired units can be measured accurately, and virtually instantaneously, using a flow meter.

Finally, the approved daily sampling method requires that SO_2 emissions be calculated using the highest measured sulfur content of the previous 30 daily samples. This prevents any possible underestimation in the unlikely event that a daily sample had a lower sulfur content than the average for the entire day. It is, thus, highly improbable that any emissions would not be accounted for using this method.

Verification frequency. Although the "timeliness" criterion in section 412(a) of the Act does not unequivocally mandate exactly the same turn-around time in measurement verifications for CEMS and excepted methods that involve collection of actual measurement samples, EPA believes that the verification frequency for any monitoring method should be as short as is practical. This is important in order to provide up-to-date emissions information to the allowance market and to meet regulatory deadlines for quarterly emissions reports and the end-of-year allowance/emissions reconciliation. Nevertheless, as numerous commenters pointed out, a "next day" turn-around requirement would be particularly impractical for units covered by this exception. They are frequently located in remote areas and, due to their size and the infrequency of their burning oil, they typically must send their oil samples to outside commercial laboratories for analysis. Many commenters suggested that seven days would be the minimum reasonable amount of time to send out oil samples for analysis and receive results while others suggested a 15 or 30 day turnaround. Concern was expressed that it would be administratively impractical to conduct a 24 or even 7 day turnaround thus making this option unattractive to most, if not all, of the oil fired units for which this option is intended. As proposed, those selecting this option would be driven to inefficiently analyzing single or small batch samples. Concern was also expressed that this approach could inadvertently encourage the development of on-site, less accurate, lab analysis. Thus, EPA does not consider a seven day turnaround practical for small or remotely located units. Further, in situations where the information is needed more quickly for end of year true-up or enforcement purposes, the sample(s) could be analyzed more quickly on a case by case, as needed, basis. Thus, EPA has decided to promulgate a 30 day turnaround period.

(iii) Other considerations. EPA's analysis also indicates that this exception represents an appropriate way to reduce the particularly disproportionate financial burden that requiring SO_2 CEMS would impose on oil-fired units. Total emissions from all oil-fired units represent approximately 4 percent of the SO_2 emissions from all affected units. Nevertheless, monitoring costs under the Acid Rain Program for small oil-fired units can range as high as $490–$49,000 per ton of SO_2 emitted. The proposed exception will provide a viable, more cost effective option for such sources.

Another concern, raised by commenters, was that units qualifying for this exception might subsequently change their proportion of oil usage, thereby increasing the level of emissions not being monitored by CEMS. To address this concern, the definition of "gas-fired" has been revised in the final rule to include a cap on the amount of oil that qualifying units could use in any one-year or 3-year period. Further, by extending the option to all oil-fired units, the decision to install an SO_2 CEM system will not be capacity factor driven. The result is a simplified set of requirements that provide additional operational flexibility to units that experience atypical increases in utilization in any given year.

(c) Other suggested methods for calculating SO_2 emissions considered. Commenters proposed several other methods for determining SO_2 emissions. EPA rejected these approaches because they represented clear departures from the statutory criteria for evaluating alternative monitoring methods and because of concerns about their administration and enforceability.

Permit limit proxy. One proposal for oil-fired units was to always use the "maximum permitted" oil sulfur content as a default sulfur value for units with such permit limitations. The EPA rejected the proposal because a fuel's permitted sulfur content bears no relationship to physical measurement and verification procedures, based on actual operations, that are implicit in the word "monitoring," as mandated in the Act.

"F-factor"/fuel flow method. Other commenters proposed allowing a diluent monitor, an "F-factor," and a fuel flow meter to be used as an alternative to a CEMS volumetric flow monitor. (An "F-factor" is a fuel-specific constant that relates the heat content of a fuel and the amount of gases given off upon combustion. It is used to convert diluent gas concentration and pollutant concentration into a value of pounds of pollutant per million British thermal units of heat input.) In a four-day experiment performed by one commenter, the method appears to have produced measurements that track those generated by a combined SO_2, CEMS and volumetric flow monitor. However, EPA does not believe that four consecutive days of data are sufficient to support a conclusive equivalency determination at this time. To be approved, this method would have to meet the criteria for alternative methods in a thirty-day trial as required by the provisions of § 75.40 of the rule. If approved, this alternative method would be promulgated as an excepted monitoring method in appendix I and would apply categorically to oil-fired and gas-fired boilers.

Coal fuel sampling: EPA also considered coal fuel sampling as a method of monitoring SO_2 emissions. As with other methods suggested, EPA evaluated the method's ability to obtain accurate and representative samples and evaluated the practicality of using the method to obtain samples, determine the amount of fuel used, and calculate emissions for any given hour. Whereas flow-proportional continuous oil fuel sampling yields extremely accurate information on which to base actual emissions calculations, such accuracy cannot be consistently achieved by coal fuel sampling. Oil fuels have highly homogeneous sulfur content as compared to coal and coal-derived fuels. Comparisons of oil fuel sampling to CEMS have shown variations in contemporaneous readings of 0 to ±5 percent on an hourly basis. Similar comparisons of coal sampling to CEMS have shown variations in contemporaneous readings ranging from ±10 to ±45 percent on a daily basis, with significantly greater variations on an hourly basis.

These results are not unexpected since the physical composition of coal makes it extremely difficult to specify and use a standardized process for taking representative fuel samples. Because coal characteristically can contain large, but irregular, concentrations of impurities, the sulfur content of coal can vary greatly within a single shipment. Consequently, two adjoining chunks of coal may differ dramatically from each other. EPA does not consider that units performing coal

fuel sampling and analysis qualify for an exception to the CEMS monitoring requirements for SO_2.

(2) For NO_x CEMS

The proposed regulations included no exceptions to the NO_x CEMS requirements.

Through the public comment process, EPA received numerous proposals for exemptions from the NO_x monitoring requirements. The comments focused primarily on the category of affected units that are not coal-fired and are not, therefore subject to NO_x emission limitations under section 407 of the Acid Rain Program. Some commenters asked that such units be exempt from the title IV NO_x emissions monitoring obligations in their entirety. Others recommended an alternative method for infrequently operated (i.e., "peaking") units, such as diesel- and dual-fuel reciprocating internal combustion engine units, combustion turbines, and other oil- and gas-fired units with a capacity factor below some stipulated level.

Response: EPA disagrees with those proposing a total exemption from NO_x monitoring requirements for units that do not have a NO_x emission reduction obligation under section 407 of the Act. Section 412 of the Act clearly requires *all* units with emissions limitations under title IV, not just those with NO_x limitations, to monitor NO_x emissions. This information is important to Acid Rain Program implementation, particularly with regard to the various studies and reports mandated by the Act, which specifically identifies NO_x as a key acidic deposition precursor pollutant.

EPA agrees, however, that it is appropriate to craft a limited exception to the NO_x CEMS requirements, applicable only to gas- and oil-fired "peaking" units having a capacity of 10 percent or less over the previous three years. See discussion of *de minimis* exceptions in the preamble to part 72, Permits. These two categories of peaking units have extremely low emissions both collectively and individually. Total NO_x emissions from this category of unit is estimated at 40,000 tons per year. At the same time, the cost of monitoring NO_x emissions using CEMS could be several hundred dollars per ton of NO_x monitored. In addition, a large number of sources that fall into these two categories are located in small municipalities, where the cost of installing, operating, and maintaining CEMS would be particularly burdensome.

EPA believes that these considerations, and the fact that these categories of units are not subject to NO_x emission reduction requirements under title IV, are pertinent. The EPA believes that exceptions to monitoring requirements are appropriate to consider in cases where insignificant annual emissions are involved and the statutory objectives can be met. Specifically, the primary concern underlying the statutory emphasis on CEMS as the mandated monitoring method is the need for precise, reliable and timely information indicating the exact emissions of each unit *in order to determine whether a source or unit has met its emissions limitations.* (emphasis added). S. Rep. No. 427, 101st Cong., 1st Sess. 336–337 (1989). In short, given the absence of a compliance obligation for these two categories of units, and the high costs of installing and operating CEMS at the units, a reliable exception method would seem justified.

(a) Approved method. The final regulations allow gas- and oil-fired "peaking" units to account for their NO_x emissions using site-specific NO_x emission factor correlations at various unit loads. The term "peaking unit" is typically used by industry to describe a unit that is operated at a capacity factor of 10 percent or less. See, for example, the Electrical Power Research Institute's *Technical Assessment Guidelines* (1991), which classifies units on the basis of load. The term "capacity factor" refers to the ratio of the unit's actual electrical or steam output (in MWehr) to the output if the unit ran continuously for 8760 hours a year at the unit's rated nameplate capacity. A capacity factor of 10 percent would be typical of a unit that operates 400 hours a year. A "low capacity factor" unit typically refers to a unit that is operated at a capacity factor of 30 percent or less. The term encompasses both "intermediate load" and "peaking" units. A "high capacity factor" or "base loaded" unit refers to units operated at a capacity factor of 50 to 70 percent.

Any unit using this method will be required to develop a historical record of NO_x emissions at various loads to establish the correlations. The site-specific derivation of correlations, based on historical emissions data, is necessary, because NO_x formation is uniquely dependent on the particular operating characteristics and equipment used at a unit. Once the correlations are derived, they are applied to the unit's actual load data in order to calculate the unit's NO_x emissions for the year. In addition, periodic NO_x emissions stack testing is required to verify the continued representativeness of the correlations. The EPA believes these procedures will ensure that the correlations produce sufficiently representative data on actual emissions for this limited class of units. This approach is consistent with the recommendations of many of the commenters who identified the need for an exception to NO_x CEMS for gas- and oil-fired peaking units.

It is important to note that the approved emissions/load exception does not meet the criteria for an alternative monitoring system, as specified in section 412(a) of the Act. As such, it is only approved for use in a very limited class of units. To date, no continuous alternative NO_x monitoring system has been field tested alongside a certified NO_x CEMS and shown to meet the equivalency criteria specified in the Act. Thus, there is no exception to NO_x CEMS requirements beyond the exception for oil- and gas-fired "peaking" units.

Some commenters expressed concern that a unit, once qualified for an exception to the NO_x CEMS requirement, could then change from a low capacity factor to a high capacity factor unit, or change its fuel usage and thereby undermine the representativeness of the emissions/load correlations. To prevent this, the final rule includes a definition for "peaking unit" that links the continued availability of the NO_x monitoring exception to a unit's mode of operation during the previous three years. It provides additional operational flexibility in the case of atypical end-of-year increased utilization, while setting limits on a source's ability to qualify for an exception to the NO_x CEMS requirements. The regulations also include procedures for determining if units with fewer than three years of operating experience qualify as peaking units. If a unit's utilization changes so that it is no longer a "peaking" unit, it would become subject to the CEMS monitoring requirements in the following calendar year. Similarly, if a unit changes its fuel usage and thereby changes its emission characteristics, the owner or operator would be required to revise the unit's correlations or install a CEMS for NO_x by the end of the following calendar year.

(b) Other methods considered for NO_x exceptions: AP–42. A number of commenters promoted an approach, similar to the emissions/load correlation approach approved today, but based on the EPA-developed emission estimation factor known as AP–42. Despite superficial similarities, that approach would rely on emission factors derived from industry-wide average (i.e., generic) estimates of emissions for different fuel and boiler types. The EPA

rejects such an approach, because its estimates are not based on the actual historical operating experience of the units to which the estimates would be applied. Generic estimation would be especially detrimental in calculating NO_x emissions, because of wide variations in emissions formation characteristics from unit to unit.

The unit-specific NO_x emissions/load correlation approach approved today provides a more representative calculation of the actual emissions at a particular unit than the generic AP–42 emission estimation factors. This is especially true for combustion turbines and diesel and dual-fuel reciprocating internal combustion engines, which tend to have relatively steady and predictable NO_x emissions.

(c) Other capacity factor cut-offs. As discussed above, the exception to the NO_x CEMS requirement applies to "peaking units," defined as units with a capacity factor of 10 percent or less over the previous three years and 20 percent or less in each of those years. The EPA received proposals for NO_x CEMS exceptions based on other capacity factor cut-offs. Some commenters suggested that oil- and/or gas-fired units with a capacity factor of 30 percent or less should be able to determine NO_x emissions by an excepted method. The EPA has rejected this suggestion since it considers the NO_x emissions from existing units operating at a capacity factor between the approved 10 percent cut-off and the proposed 30 percent cut-off to be not *de minimis,* either individually or as a group. Such units can emit more NO_x than many coal-fired units affected in Phase I of the program. According to the NURF database, the entire category of 30 percent or less, gas- and oil-fired units emitted approximately 400,000 tons of NO_x in 1985.

(3) For Opacity Monitoring

The proposed rule contained two classes of exemptions to the part 75 requirement that affected units install continuous opacity monitors. Gas-fired units that derived no less than 90 percent of their total annual heat input from natural gas were exempt as were wet scrubbed units. These and all other affected units would still be required to meet any other applicable federal, state, and local opacity monitoring requirements.

Some commenters suggested that the opacity monitoring requirements under the Acid Rain Program should not go beyond other existing federal, state, and local requirements.

Response: EPA cannot adopt this proposal, since section 412 of the Clean Air Act Amendments requires the installation of continuous opacity monitors at all affected units. There appear to be a substantial number of affected units combusting residual oil which exhibit significant opacity levels, yet are not subject to opacity monitoring requirements in every state. The opacity data, obtained under part 75 of these regulations, is to be sent to state and local air control agencies.

However, the Agency is using its discretionary authority to provide class exemptions for units that do not have significant opacity levels and for units that may not be able to provide meaningful opacity information. Thus, in the interest of meshing the Acid Rain Program opacity monitoring requirements with those of pre-existing federal, State, and local air quality programs, the final rule exempts gas-fired units that combust natural gas for no less than 90 percent of their total heat input during the previous three calendar years and diesel and dual-fuel reciprocating internal combustion engine units. As noted in the preamble to the proposed rule, gas-fired units have very low opacity levels, and extremely few of them (less than 5 percent of the 90-percent gas-fired units in the National Allowances Database) are required to monitor for opacity under other federal, State, or local regulations. Likewise, states such as Indiana, Iowa, and Kansas with many diesel and dual-fuel reciprocating internal combustion engines do not require the monitoring of opacity because of low opacity levels (e.g. below 10 percent opacity, even during startup). Nevertheless, where such requirements exist, this exception for title IV purposes has no effect on a unit's obligation to comply with other provisions of the Act. *See Alabama Power Co.* v. *Costle,* 636 F. 2d 323, 360–61 (D.C. Cir. 1979).

One commenter remarked that many wet scrubbed units successfully monitor for opacity under state programs and suggested that it would be appropriate for EPA to require opacity monitors on wet scrubbed units.

Response: EPA acknowledges that it is sometimes possible to monitor opacity in the stack or at the inlet of wet scrubbed units, depending on site-specific conditions such as the temperature of the flue gas. Therefore, under the final rule, only wet scrubbed units where condensed water is present are exempted from opacity monitoring for acid rain purposes. Nevertheless, if the State, local, and other federal programs require monitoring of opacity, then compliance with those regulations is still required.

Another commenter expressed concern that the opacity monitoring requirements might be avoided by units whose classification changes from "gas-fired" to "oil-fired," due to their using a higher proportion of oil for their heat input.

Response: The Agency has revised its definition of a "gas-fired" unit to allow units to use a three year period in calculating the proportion of their heat input derived from natural gas. This will reduce the likelihood of a unit's being accidentally reclassified without significantly changing the characteristics of its emissions. However, if a unit should still exceed the specified proportion of oil in its fuel blend and thereby change its emission characteristics, the owner or operator is required to install and certify a continuous opacity monitor within 365 days of the occurrence of the change in classification.

(4) For Clean, Small New Units

In the proposed rule, EPA requested comment on whether exceptions to some or all of the Acid Rain Program requirements should be extended to small new units, based on the relative insignificance of their total emissions. Existing units of less than 25MWe capacity are exempt from the title IV by virtue of the statutory definition for "existing unit," but there is no explicit exemption for small new units. Specifically, EPA asked whether small generators that only incidentally supply power to the grid should be subject to the full range of Acid Rain Program requirements. The overwhelming majority of those who commented on the issue believed that some form of relief would be appropriate for small new units with low emissions. Various demarcations were suggested by the commenters for defining the categories of units that would qualify for such an exception. They include: A size cutoff in MWe, with commenters suggesting sizes ranging from 5 to 25 MWe; a tonnage emissions cutoff such as that used in EPA's Prevention of Significant Deterioration air pollution control programs; and exceptions based on boiler or engine type. Two related concerns, particularly noted by the commenters, were the relatively high, per-unit cost of monitoring extremely small sources (i.e., those emitting in the range of one-ton of SO_2 per year), and the unusual burden these costs would impose on small generators and small communities. Commenters also drew attention to the heavy burden, both to sources and to EPA, that would result from having to issue acid rain permits to all such units.

Response: As is discussed more fully in the preamble to part 72, the Agency agrees with the commenters that a conditional *de minimis* exception to the emissions reduction, permitting, and monitoring requirements of the Acid Rain Program is appropriate for small, new, "clean" units. Specifically, units having a nameplate capacity of 25 MWe or less and combusting fuels with a sulfur content not greater than .05 percent by weight would be conditionally excepted from all Acid Rain Program emission reduction, permitting and monitoring requirements, subject to a continuing requirement to certify their eligibility for this exception. EPA's analysis indicates that the sulfur content standard of this exception would be met by units combusting natural gas and by units combusting diesel fuel refined to meet requirements in the Clean Air Act Amendments for on-road vehicles. Those units that do not meet the nameplate capacity and fuel sulfur content criteria will be required to meet all title IV Acid Rain Program requirements. Moreover, EPA will reconsider the exception if significant increases in emissions from this category are found to occur in the future. EPA believes that this exception, and the safeguards associated with it, are in keeping with the Administrator's authority to grant *de minimis* exceptions.

VI. Discussion of Changes to Part 77—Excess Emissions

Part 77 sets forth the requirements for units that have sulfur dioxide or nitrogen oxide emissions in excess of their emissions limitations. Units with excess emissions of sulfur dioxide must submit offset plans providing for the deduction of allowances equal to the tonnage of excess emissions and must pay $2,000 (as adjusted by the Consumer Price Index) per ton of excess emissions. Units with excess emissions of nitrogen oxides also must pay a $2,000 per ton penalty. In addition, interest is owed for late penalty payments.

A. Restructuring Changes

In response to general comments encouraging streamlining of the rules, portions of part 77 have been reorganized and simplified. First, like all the definitions of terms in other parts of the rule, definitions from part 77 have been consolidated in § 72.2. Further, provisions that were redundant with generally applicable provisions in part 72 were deleted. These include applicability, federal and state authority, signatory requirements, and recordkeeping. The substance of these provisions (including the reservation of federal authority) was not altered by this organizational change. Finally, Appendix A was deleted. It duplicated certain provisions already in the rule and provided information, showing the calculation of the excess emission penalty, that is more appropriately left for guidance materials.

B. Response to Comment

(1) Offset Plans for Excess Emissions of Sulfur Dioxide

Section 77.2 of the proposed rule required that each offset plan contain specific, detailed information about every unit with excess emissions. For example, the proposed rule required that the plan explain how and why excess emissions occurred at the unit, what corrective actions had been taken, and the schedule and increments of progress for offsetting the emissions in the future. A unit wishing to use a new compliance option to obtain allowances for offsetting had to include the planning requirements for that option in the offset plan.

The Agency received numerous comments on this section of the rule. In general, the commenters thought the offset planning process was unnecessarily lengthy, burdensome, and complicated. Moreover, they strongly supported eliminating most of the offset information and scheduling requirements, especially for cases where an offset plan simply calls for deduction of allowances from the excess emitting unit's account in the year after the excess emissions occurred. In addition, a few commenters questioned the Agency's authority to impose certain information requirements.

Response: Section 411 of the Act requires the owners and operators of a unit with excess emissions to submit "a proposed plan to achieve the required offsets," which plan the Administrator will approve "as submitted, modified, or conditioned." This provision gives EPA the discretion to require information deemed necessary to review offset plans and to determine what conditions to require. Further, Congress intended that offset plans could be broader than simply a statement of when allowances would be deducted. See 136 Cong. Rec. S16969, 16982, daily ed., October 27, 1990 (stating that the offset plan should show how source will reduce its emissions to achieve the requirements of title IV, including a plan to achieve required offsets). Nevertheless, in light of the comments supporting an easing of the regulatory burden, the Agency has reconsidered its approach for carrying out section 411 and has simplified the requirements for offset plans.

Information requirements have been tailored to fit the type of offset plan that is submitted and the compliance status of the unit involved. In general, if a plan specifies an immediate deduction of allowances to offset excess emissions, no additional information is required. Only if the unit has had excess emissions for two years in a row must the plan include information on how the excess emissions occurred and what measures are being taken to prevent excess emissions in the future. If a plan specifies a deduction of allowances at a date after the year following the year in which excess emissions occurred, the plan must in addition demonstrate that deducting the allowances earlier would interfere with electric reliability. However, compliance options are no longer tied to offset plans and are submitted separately as permit revisions.

There are several reasons for these changes. First, the Agency believes that by simplifying the proposed rule, it can ease the regulatory burden on sources and on the Agency without any adverse environmental impact. The Agency believes that in most cases an offset plan that simply requires immediate surrender of allowances to offset excess emissions will be sufficient. Such a plan, coupled with the automatic penalty of $2,000 per ton of excess emissions and the enforcement remedies under other sections of the Act, provides a strong incentive for owners and operators to be in compliance. However, a more detailed plan, including compliance schedules, may be needed in unusual cases, e.g., to ensure immediate and appropriate steps are taken to bring a unit with recurring and egregious violations back into compliance. The Agency believes that, in cases of repeated excess emissions, information on the cause of the excess emissions and measures to prevent future excess emissions will assist in determining whether a more detailed offset plan is necessary. The Agency has reserved the authority to require detailed schedules of compliance on a case-by-case basis and intends to use this authority only in extraordinary cases.

Second, even though some of the upfront information requirements have been deleted, the Agency's ability to obtain information about the unit has not been compromised. The Administrator still retains the discretion to ask for supplemental information under this part and also has the broad

authority to demand information under sections 114 and 307 of the Act.

Finally, while a compliance option (such as substitution or reduced utilization) may no longer be approved as part of the offset plan, units retain the flexibility that they had, under the proposal, to use compliance options to accomplish the offsets. Under the final rule, a unit may still use the permit revision procedures in part 72 to obtain approval for a compliance option. Depending on whether the unit obtains approval for an offset plan with delayed deductions of offset allowances, newly available allowances under an approved compliance option can be used directly to make offsets or to replenish the unit's account after offset allowances have already been deducted. Under this approach, a compliance option is approved under the same procedures in part 72 regardless of whether the unit involved had excess emissions in the prior year. Of course, the choice of a compliance option will not alter or stay the requirements of the offset plan.

(2) Administrator's Action on Proposed Offset Plans

The proposed rule required each proposed offset plan, regardless of how simple or complex it was, to undergo the same approval process. This process included a public notice and public comment period and was to be completed within six months of the proposed offset plan's submission. Several commenters questioned the Agency's authority to provide public notice and comment and recommended shortening the approval process for at least the simplest kinds of offset plans. The six-month approval process was viewed as serving only to delay expeditious compliance with the offset requirements.

Response: The Agency believes that it has the same authority to provide for notice and comment for an offset plan, which conditions a permit, as it has with regard to the permit itself. Nonetheless, in light of these comments and the simplified approach the Agency has taken to offset planning, the Agency has decided to shorten the process for approving most offset plans.

Accordingly, the Agency has divided offset plans into two categories: Those that specify deducting allowances immediately and those that specify deducting allowances at a later date. In the latter case, the offset plan will still go through the up-to-six-month approval process described in § 77.4 of the final rule. This is essentially the same process that was laid out in the proposal. When a unit wants allowances deducted later in the year or in a subsequent year, the public should have the opportunity to comment, e.g., on why allowances are not being immediately deducted or whether a more detailed plan is appropriate.

The Agency will generally deal with the first category of offset plans in a much simpler way. If a proposed offset plan specifies deducting allowances immediately and the allowances are in the unit's account, the plan may be approved without further review as an automatic amendment to the permit. The Agency believes that, in general, a public notice and comment period in such a case would serve no purpose. In requiring the soonest possible deduction of allowances, the offset plan already meets the requirement, under section 411(b) of the Act, that allowances be deducted from those allocated for the source. Notice and comment would only delay the offsetting of emissions that would otherwise occur soon after submission of the proposed offset plan. However, in those exceptional cases where, despite the submission of a plan calling for immediate deductions, the Agency determines that a more detailed offset plan with compliance schedules is necessary, the public should have an opportunity to comment on the schedules. Therefore, the six-month approval process will apply.

(3) Interest on Penalties for Excess Emissions

The proposal required the owners and operators to pay interest on the automatic $2,000 penalty for each ton of excess emissions if the penalty payment was late. The Agency received numerous comments concerning the interest requirement. In general, commenters questioned whether the Agency had the authority to collect interest on the penalties. Furthermore, they strongly argued that at a minimum, if a penalty payment was late, interest should accrue from the due date of the penalty, not January 1.

Response: The Agency clearly has the authority to collect interest on penalties. That authority comes from the Debt Collection Act, 31 U.S.C. 3717, which allows the head of an executive agency to charge a minimum annual rate of interest on an outstanding debt on a United States government claim. However, the Debt Collection Act provides that interest accrues from the date on which notice of the amount due is first mailed to the debtor. Therefore, the Agency has revised the rule to require that, for any penalty payment not made in full within 60 days of the end of the year in which excess emissions occurred, interest accrues from the date on which a demand notice from the Agency is mailed. Consistent with the Debt Collection Act, interest will not be charged if the claim is paid within 30 days after the date that notice of the amount due is mailed to the debtor.

VII. Discussion of Changes to Part 78—Administrative Appeals

Proposed subpart H of part 72 (renamed part 78) provided the procedures for administrative appeals of certain decisions of the Administrator under the Acid Rain Program. The basic approach to administrative appeals taken in the final part 78 rule is the same as that in the proposal, with a few changes. References in the proposal to the Administrator have been changed to refer, in the final rule, to the Environmental Appeals Board. In the past, appeals to the Administrator were delegated to the Chief Judicial Officer or decided by the Administrator. On February 13, 1992, the Agency established the Environmental Appeals Board of three members who will take over the appellate functions formerly exercised by the Chief Judicial Officer and the Administrator. (See 57 FR 5320, February 13, 1992.)

Further, references to "submit" or "submissions" have been changed to refer to "file" or "filing." This reflects the fact that, for purposes of applying the filing deadlines set forth in part 78, the date of receipt by the Administrator, Environmental Appeals Board, Presiding Officer, or Hearing Clerk (as appropriate), not of sending, is determinative. Also, as part of an effort to streamline the role, some provisions (e.g., proposed §§ 72.101(c)(2) and (d)) were deleted as unnecessary or redundant in light of the broad authority of the Presiding Officer under other provisions.

A. Expansion of Appeals to Allowance Rule Decisions

Proposed part 72, subpart H applied only to the Administrator's decisions concerning Acid Rain permits but the Agency stated in the preamble to the proposal that it was considering whether the appeals procedure should cover other decisions under the Acid Rain Program. The Agency received numerous comments requesting that the appeals procedures be expanded to cover other decisions. In particular, commenters noted the account error and dispute resolution process, proposed in § 73.37, applicable to allowance transfers recorded by the Administrator in the Allowance Tracking System. While the commenters generally supported that process, several commenters suggested that the appeals

procedure in part 72, subpart H be expanded to cover decisions of the Administrator under part 73, as a supplement to the account error and dispute resolution process.

Response: The Agency agrees that the administrative appeals procedure should be available for decisions of the Administrator under part 73. The final rules therefore include a provision allowing appeals regarding various decisions on the transfer, allocation, sale, return, or deduction of allowances by the Administrator. The administrative appeals procedure may not, however, be used to challenge provisions or requirements promulgated in regulations, including part 73.

Like the account error and dispute resolution procedure, only the authorized account representative of the account involved may appeal decisions under part 73 (e. g., allowance allocations under compliance options). This minimizes interference with the operation of the Allowance Tracking System and the allowance market. However, decisions under part 72 affecting allowances (e.g., decisions on compliance options resulting in allowance allocations) may be appealable by other interested persons.

B. Expansion to Monitoring Rule Decisions

Many commenters also supported using the administrative appeals procedure for decisions of the Administrator under part 75 because of the critical role that monitoring plays in the Acid Rain Program.

Response: The Agency agrees and the final rules allow monitoring decisions of the Administrator to be appealed under part 78, including the following: (1) The decision on petition for approval of an alternative monitoring system; (2) the approval or disapproval of a monitor certification or recertification: (3) finalization of annual emissions data, including retroactive adjustments based on audits; (4) the determination of the percentage emissions reduction achieved by Phase I extension technology; and (5) the determination on the acceptability of parametric missing data procedures. The Agency is providing for appeal of these decisions because they involve judgement and discretion on the part of the Administrator, rather than a blanket application of the regulations in part 75. These administrative appeals procedures may not be used to challenge the part 75 regulations.

C. Other Related Changes

Consistent with the expansion of the scope of the administrative appeals procedures in the final rule, the final rule applies these procedures to various decisions (in addition to the issuance or denial of permits) under the permits rule, including the issuance or denial of written exemptions for new and retired units, the determination of the incompleteness of an Acid Rain permit application, and the deduction or return of allowances under the compliance options. The procedures also now apply to the approval or disapproval of excess emissions offset plans and related allowance deductions under part 77.

Moreover, the significantly broader scope of Agency decisions subject to administrative appeal is likely to impose a much heavier burden on the Environmental Appeals Board and the Administrative Law Judges in terms of the number and complexity of the cases. Consequently, certain provisions of the proposal have been changed in order to ease that burden and ensure sufficient time for reasoned decision-making. In particular, under the final rule, the Presiding Officer in an evidentiary proceeding must issue a proposed decision "within a reasonable time" after completion of the hearing, rather than within 90 days as required in the proposal. Similarly, rulings on motions must be made within a reasonable time, rather than within 60 days.

Finally, the expansion of the appeals procedures means that they may apply to decisions on matters concerning which there was no opportunity to file comments or claims of error before the appeal. For the latter decisions, the final rule places the burden of going forward on the Administrator. Except for such cases, the petitioner has the burden of going forward. In all cases, the petitioner or, where the issuance or denial of an Acid Rain permit and a written exemption is involved, the prospective permittee has the burden of persuasion. This is consistent with the discussion of burden of proof in the portion of the preamble for the proposed rule addressing appeals.

VIII. Impact Analyses

A. Executive Order 12291

Under Executive Order 12291, the Administrator must judge whether a regulation is "major" and therefore subject to the requirement to conduct a Regulatory Impact Analysis (RIA). This rule package is "major" as defined in 1(b) of E.O. 12291 because the annual effect on the economy will be greater than $100 million. While the annual effect on the economy will be greater than $100 million, EPA does not anticipate major increases in prices, costs, or other significant adverse effects on competition, investment, productivity, or innovation or on the ability of United States enterprises to compete with foreign enterprises in domestic or foreign markets due to the proposed regulations.

Title IV, on its own without any implementing regulations, mandates extensive emission reductions and imposes continuous emission monitoring requirements on all sources. The reductions basically impose a reduction in emissions equal to the limit of allocated "basic" allowances. Such a program costs much more than the program assuming allowance trading, which provides for flexible, cost-effective compliance, the permits program, which provides for special compliance options such as the Phase I technology reserve program, and the monitoring program, which allows sources to implement alternative monitoring systems if they are demonstrated to match or exceed CEM systems.

A high base case and a low base case scenario were used in the analysis. These two cases were used by EPA to estimate the impacts of the legislation during the debate in Congress.

EPA's RIA evaluates the effects of a set of three regulations termed the "implementation regulations." These regulations are the General Provisions and Permits regulation; the Allowance System regulation, including tracking, transfers, auctions and sales, and conservation and renewable energy; and the Continuous Emissions Monitoring regulation. Collectively, this set of implementation regulations establishes and implements the core of the acid rain program. NO_x control costs were not included in this analysis.

EPA estimated the costs of achieving the reductions in SO_2 emissions under the statute and the implementation regulations for the time period from 1993 through 2010. While the total costs will be much lower in Phase I than Phase II, this analysis annualized the costs over the entire 18-year period. The statute without the implementation regulations (absent regulations case) imposes substantial costs, with the total annualized costs ranging from $1.6 to $2.5 billion per year. The costs of the implementation regulations (regulatory case), with total annualized costs ranging from $0.9 to $1.5 billion, are substantially less than the costs of the statute absent the implementation regulations. Thus, to achieve the mandated SO_2 emission reductions, the implementation regulations result in annual cost savings of between $0.7 and $1 billion compared to the statute absent the regulations.

While these costs are large in absolute terms, they are relatively small compared to the $200 billion average annual costs of generating electricity. The annualized costs of the implementation regulations are estimated to increase the annual costs of generating electricity by 0.5 to 1.2 percent.

For permitting under the regulatory case, program participants will incur administrative costs to obtain permits. The administrative cost for affected sources to obtain permits is estimated to be $0.5 million per year for Phase I (1995–1999) and $5.4 million per year for Phase II (2000–2010). Under the absent regulations case, no permitting would take place, so there would be no costs associated with permits.

In the regulatory case, EPA estimates that the total impact for participants in the allowance trading market will range between $15 and $30 million per year. This estimate includes market evaluation and transactions costs. These costs are based on the assumption that transactions costs will average 1.5 percent of the value of trades, which is assumed to range between $1 and $2 billion annually. In the absent regulations case, no trading would occur, so there would be no transaction costs in that case.

Although the auction and direct sale regulations are not included in this rulemaking, the costs are presented here for completeness. The total estimated annual costs to auction participants are minor, ranging from $13,600 to $81,300. The estimated total costs for direct sale applicants is $13,500 over 2 years. Assuming all IPP guarantee applications occur in the first year, the total cost to IPP guarantee applicants is estimated to be $225,000.

The conservation and renewable energy reserve is an optional program intended to provide additional incentive for utilities to conduct conservation programs. Affected sources that choose to participate in this program are likely to do so because it is economically beneficial. Under the regulatory case, the cost to affected sources that choose to participate associated with obtaining allowances from the conservation and renewable energy reserve is estimated to be $100,000 to $200,000 per year. These costs include the burden to assemble and submit an application to EPA each year in order to receive allowances from the reserve. Under the absent regulations case, no conservation and renewable energy reserve would be established.

For monitoring, the costs to the regulated community under the absent regulations case include costs associated with the installation and maintenance of continuous emissions monitors (CEMs), continuous opacity monitors (COMs), and flow monitoring systems, if they do not already have one in place. No alternative monitoring methods would be allowed and no data reporting costs would be incurred. In this case the estimated cost to the regulated community is $195 million annually.

The analysis considered five monitoring options under the regulatory case. All five options include operation and maintenance requirements. Option 1 presents the most stringent regulatory case and has an estimated annualized cost to electric utilities of $239 million dollars. Option 2 some monitoring exceptions and is estimated to cost $211 million annually. Option 3 exempts retiring plants from all monitoring requirements and has an estimated annualized cost of $234 million. Option 4 requires the use of standardized data reporting and recordkeeping requirements and is estimated to cost $235 million annually. Finally, EPA's proposed option, Option 5 has an estimated annualized cost of $184 million.

Both the absent regulation and regulatory cases will yield environmental benefits due to the 10 million ton reduction in SO_2 below 1980 levels. The reductions will result in less acid rain and sulfate exposure, and better visibility and local air quality. The implementation regulations are expected to generate additional long run benefits by creating incentives for the development of improved pollution control technology.

The analysis is contained in the Regulatory Impact Analysis (RIA) of the Acid Rain Regulations, July 1992, EPA, Office of Atmospheric and Indoor Air Programs.

This rule and RIA were submitted to the Office of Management and Budget (OMB) for review prior to publication as required by E.O. 12291.

B. Regulatory Flexibility Act

The Regulatory Flexibility Act of 1980 requires each Federal agency to perform a Regulatory Flexibility Analysis for all rules that are likely to have a "significant impact on a substantial number of small entities."

For the purposes of this analysis, EPA used the Small Business Administration definition that a small electric power utility is one that generates a total of less than 4 billion kilowatt-hours per year. Not all small utilities are affected by the acid rain Title of the Act. Utilities will be unaffected if all of their units are: (1) Exempt (e.g., units use non-fossil sources of energy or simple gas turbines), or (2) below statutory minimums for electric generating capacity (e.g., generate less than 25 megawatts).

To examine the effects on small entities, EPA constructed six model small utilities of varying fuel type and size to represent most of the small utility population. Costs of SO_2 reductions are the incremental costs of acid rain controls, relative to the pre-statute case, under the absent regulations and regulatory cases. The implementation regulations lead to cost savings (or no change) relative to the absent regulations case for four of the six model utilities. However, even after the reductions in cost provided by the implementation regulations, the impacts on some small coal- and oil-fired utilities are expected to be significant. In the worst case, the regulatory cost to these utilities could represent between 6 to 7 percent of the average value of electricity produced in the year 2000. About 36, or one-third, of the 105 affected small utilities could face impacts of up to this magnitude. The other two-thirds have regulatory impacts that are comparable to or less than the impacts on all utilities as a group.

EPA's analysis concludes that virtually all of the impacts on small entities are caused by statutory provisions of the Act. Although EPA's regulations are intended to mitigate some of the burden on small businesses, the statutory provisions restrict the amount of relief that can be given. The implementation regulations are likely to result in substantial reductions in the costs imposed by the statute on small entities. As a percentage of the costs under the absent regulations case, the savings provided by the regulations may be similar to the savings for larger utilities. In addition, the rules provide an exemption from all title IV requirements for all new utility units that serve one or more generators, the nameplate capacities of which total 25 MWe or less, and that use fuels with a sulfur content less than or equal to .05% by weight. The rules also provide an exception from the NO_x monitoring requirements for gas-fired units with capacity factors of 10% or less. Therefore, by implementing these regulations, EPA has provided all the relief available under the statute to help the most affected small utilities. Based on this analysis and pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this attached rule, if promulgated, will not have a significant economic impact on a substantial number of small entities.

C. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* These requirements are not effective until OMB approves them and a technical amendment to that effect is published in the **Federal Register.**

The total public reporting burden for these regulations is estimated to range between 41,000 and 45,000 hours in 1993; 38,000 and 42,000 hours in 1994; and 64,000 and 67,000 hours in the first nine months of 1995. In order to obtain a permit, the public reporting burden to develop a permit application and compliance plan including certification of a designated representative is estimated to average a total of 370 hours per application. For tracking and transferring allowances, the public reporting burden to complete and submit an allowance tracking system new account application (if necessary) and an allowance transfer form is estimated to average 30 hours and 2 hours respectively. The burden for assembling and submitting an application to obtain allowances from the conservation and renewable energy reserve is estimated to average 80 hours per application. Finally, to meet the emissions monitoring requirements, the public reporting burden is estimated to average 40 hours per report per plant for preparing and submitting quarterly emissions data reports, and 20 hours per plant for submitting a one-time monitoring plan. These burden estimates include time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing the collection of information.

Send comments regarding these burden estimates or any other aspect of this collection of information, including suggestions for reducing this burden, to Chief, Information Policy Branch; U.S. Environmental Protection Agency; 401 M St., SW. (PM–223Y); Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 726 Jackson Place NW, Washington, DC 20503, marked "Attention: Desk Officer for EPA."

IX. Supporting Information

List of Subjects

40 CFR Parts 72 and 75

Air pollution control, Compliance plans, Continuous emissions monitors, Electric utilities, Incorporation by reference, Nitrogen oxides, Permits, Reporting and recordkeeping requirements, and Sulfur dioxide.

40 CFR Parts 73, 77, and 78

Air pollution control, Compliance plans, Continuous emissions monitors, Electric utilities, Nitrogen oxides, Permits, Reporting and recordkeeping requirements, Sulphur dioxide.

Dated: October 26, 1992.

William K. Reilly,

Administrator, U.S. Environmental Protection Agency.

For the reasons set forth in the preamble chapter I of title 40 of the Code of Federal Regulations is amended as follows:

1. Title 40 is amended by adding part 72 to read as follows:

PART 72—PERMITS REGULATION

Subpart A—Acid Rain Program General Provisions

Sec.
72.1 Purpose and scope.
72.2 Definitions.
72.3 Measurements, abbreviations, and acronyms.
72.4 Federal authority.
72.5 State authority.
72.6 Applicability.
72.7 New units exemption.
72.8 Retired units exemption.
72.9 Standard Requirements.
72.10 Availability of information.
72.11 Computation of time.
72.12 Administrative Appeals.
72.13 Incorporation by Reference.

Subpart B—Designated Representative

72.20 Authorization and responsibilities of the designated representative.
72.21 Submissions.
72.22 Alternate designated representative.
72.23 Changing the designated representative, alternate designated representative; changes in the owners and operators.
72.24 Certificate of representation.
72.25 Objections.

Subpart C—Acid Rain Applications

72.30 Requirement to apply.
72.31 Information requirements for Acid Rain permit applications.
72.32 Permit application shield and binding effect of permit application.
72.33 Identification of Dispatch System.

Subpart D—Acid Rain Compliance Plan and Compliance Options

72.40 General.
72.41 Phase I substitution plans.
72.42 Phase I extension plans.
72.43 Phase I reduced utilization plans.
72.44 Phase II repowering extensions.

Subpart E—Acid Rain Permit Contents

72.50 General.
72.51 Permit shield.

Subpart F—Federal Acid Rain Permit Issuance Procedures

72.60 General.
72.61 Completeness.
72.62 Draft permit.
72.63 Administrative record.
72.64 Statement of basis.
72.65 Public notice of opportunities for public comment.
72.66 Public comments.
72.67 Opportunity for public hearing.
72.68 Response to comments.
72.69 Issuance and effective date of acid rain permits.

Subpart G—Acid Rain Phase II Implementation

72.70 Relationship to title V operating permit program.
72.71 Approval of state programs—general.
72.72 State permit program approval criteria.
72.73 State issuance of Phase II permits.
72.74 Federal issuance of Phase II permits.

Subpart H—Permit Revisions

72.80 General.
72.81 Permit modifications.
72.82 Fast-track modifications.
72.83 Administrative permit amendment.
72.84 Automatic permit amendment.
72.85 Permit reopenings.

Subpart I—Compliance Certification

72.90 Annual compliance certification report.
72.91 Phase I unit adjusted utilization.
72.92 Phase I unit allowance surrender.
72.93 Units with Phase I extension plans.
72.94 Units with repowering extension plans.
72.95 Allowance deduction formula.
72.96 Administrator's action on compliance certifications.

Appendix A to Part 72—Methodology for Annualization of Emissions Limits

Appendix B to Part 72—Methodology for Conversion of Emissions Limits

Appendix C to Part 72—Actual 1985 Yearly SO_2 Emissions Calculations

Authority: 42 U.S.C. 7651, *et seq.*

Subpart A—Acid Rain Program General Provisions

§ 72.1 Purpose and scope.

(a) *Purpose.* The purpose of this part is to establish certain general provisions and the operating permit program requirements for affected sources and affected units under the Acid Rain Program, pursuant to title IV of the Clean Air Act, 42 U.S.C. 7401, et seq., as amended by Public Law 101–549 (November 15, 1990).

(b) *Scope.* The regulations under this part set forth certain generally applicable provisions under the Acid Rain Program. The regulations also set forth requirements for obtaining three types of Acid Rain permits, during Phases I and II, for which an affected source may apply: Acid Rain permits

issued by the United States Environmental Protection Agency during Phase I; the Acid Rain portion of an operating permit issued by a State permitting authority during Phase II; and the Acid Rain portion of an operating permit issued by EPA when it is the permitting authority during Phase II. The requirements under this part supplement, and in some cases modify, the requirements under part 70 of this chapter and other regulations implementing title V for approving and implementing State operating permit programs and for federal issuance of operating permits under title V, as such requirements apply to affected sources under the Acid Rain Program.

§ 72.2 Definitions.

The terms used in this part, in parts 73, 75, 77 and 78 of this chapter, and in regulations implementing sections 407 and 410 of the Act, shall have the meanings set forth in the Act, including sections 302 and 402 of the Act, and in this section, as follows:

Account number means the identification number given by the Administrator to each Allowance Tracking System account pursuant to § 73.31(d) of this chapter.

Acid Rain compliance option means one of the methods of compliance used by an affected unit under the Acid Rain Program as described in a compliance plan submitted and approved in accordance with subpart D of this part or regulations implementing section 407 of the Act.

Acid Rain emissions limitation means:

(1) For the purposes of sulfur dioxide emissions:

(i) The tonnage equivalent of the allowances authorized to be allocated to an affected unit for use in a calendar year under section 404 (a)(1) and (a)(3) of the Act, or the basic Phase II allowance allocations authorized to be allocated to an affected unit for use in a calendar year;

(ii) As adjusted:

(A) By allowances allocated by the Administrator pursuant to section 403, section 405 (a)(2), (a)(3), (b)(2), (c)(4), (d)(3), and (h)(2), and section 406 of the Act;

(B) By allowances allocated by the Administrator pursuant to subpart D of this part; and thereafter

(C) By allowance transfers to or from the compliance subaccount for that unit that were recorded or properly submitted for recordation by the allowance transfer deadline as provided in § 73.35 of this chapter, after deductions and other adjustments are made pursuant to § 73.34(c) of this chapter; and

(2) For purposes of nitrogen oxides emissions, the applicable limitation established by regulations promulgated by the Administrator pursuant to section 407 of the Act, as modified by an Acid Rain permit application submitted to the permitting authority, and an Acid Rain permit issued by the permitting authority, in accordance with regulations implementing section 407 of the Act.

Acid Rain emissions reduction requirement means a requirement under the Acid Rain Program to reduce the emissions of sulfur dioxide or nitrogen oxides from a unit to a specified level or by a specified percentage.

Acid Rain permit or permit means the legally binding written document, or portion of such document, issued by a permitting authority under this part (following an opportunity for appeal pursuant to part 78 of this chapter or any State administrative appeals procedure), including any permit revisions, specifying the Acid Rain Program requirements applicable to an affected source, to each affected unit at an affected source, and to the owners and operators and the designated representative of the affected source or the affected unit.

Acid Rain Program means the national sulfur dioxide and nitrogen oxides air pollution control and emissions reduction program established in accordance with title IV of the Act, this part and parts 73, 75, 77, and 78 of this chapter, and regulations implementing sections 407 and 410 of the Act.

Act means the Clean Air Act, 42 U.S.C. § 7401, et seq. as amended by Public Law No. 101–549 (November 15, 1990).

Actual SO_2 emissions rate means the annual average sulfur dioxide emissions rate for the unit (expressed in lb/mmBtu), for the specified calendar year; *provided* that, if the unit is listed in the NADB, the "1985 actual SO_2 emissions rate" for the unit shall be the rate specified by the Administrator in the NADB under the data field "SO2RTE."

Add-on control means a pollution reduction control technology that operates independent of the combustion process.

Additional advance auction means the auction of advance allowances that were offered the previous year for sale in an advance sale.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Advance allowance means an allowance that may be used for purposes of compliance with a unit's Acid Rain sulfur dioxide emissions limitation requirements beginning no earlier than seven years following the year in which the allowance is first offered for sale.

Advance auction means an auction of advance allowances.

Advance sale means a sale of advance allowances.

Affected source means a source that includes one or more affected units.

Affected unit means a unit that is subject to any Acid Rain emissions reduction requirement or Acid Rain emissions limitation.

Affiliate shall have the meaning set forth in section 2(a)(11) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(11), as of November 15, 1990.

Allocate or allocation means the initial crediting of an allowance by the Administrator to an Allowance Tracking System unit account or general account.

Allowable SO_2 emissions rate means the most stringent federally enforceable emissions limitation for sulfur dioxide (in lb/mmBtu) applicable to the unit for the specified calendar year, or for such subsequent year as determined by the Administrator where such a limitation does not exist for the specified year; *provided* that, if the unit is listed in the NADB, the "1985 allowable SO_2 emissions rate" for the unit shall be the rate specified by the Administrator in the NADB under the data field "1985 annualized boiler SO_2 emission limit."

Allowance means an authorization by the Administrator under the Acid Rain Program to emit up to one ton of sulfur dioxide during or after a specified calendar year.

Allowance deduction, or deduct when referring to allowances, means the permanent withdrawal of allowances by the Administrator from an Allowance Tracking System compliance subaccount to account for the number of the tons of SO_2 emissions from an affected unit for the calendar year, for tonnage emissions estimates calculated for periods of missing data as provided in part 75 of this chapter, or for any other allowance surrender obligations of the Acid Rain Program.

Allowances held or hold allowances means the allowances recorded by the Administrator, or submitted to the Administrator for recordation in accordance with § 73.50 of this chapter, in an Allowance Tracking System account.

Allowance reserve means any bank of allowances established by the Administrator in the Allowance

Tracking System pursuant to sections 404(a)(2) (Phase I extension reserve), 404(g) (energy conservation and renewable energy reserve), or 416(b) (special allowance reserve) of the Act, and implemented in accordance with part 73, subpart B of this chapter.

Allowance Tracking or ATS means the Acid Rain Program system by which the Administrator allocates, records, deducts, and tracks allowances.

Allowance Tracking System account means an account in the Allowance Tracking System established by the Administrator for purposes of allocating, holding, transferring, and using allowances.

Allowance transfer deadline means midnight of January 30 or, if January 30 is not a business day, midnight of the first business day thereafter and is the deadline by which allowances may be submitted for recordation in an affected unit's compliance subaccount for the purposes of meeting the unit's Acid Rain emissions limitation requirements for sulfur dioxide for the previous calendar year.

Alternative monitoring system means a system or a component of a system designed to provide direct or indirect data of mass emissions per time period, pollutant concentrations, or volumetric flow, that is demonstrated to the Administrator as having the same precision, reliability, accessibility, and timeliness as the data provided by a certified CEMS or certified CEMS component in accordance with part 75 of this chapter.

As-fired means the taking of a fuel sample just prior to its introduction into the unit for combustion.

Auction subaccount means a subaccount in the Special Allowance Reserve, as specified in section 416(b) of the Act, which contains allowances to be sold at auction in the amount of 150,000 per year from calendar year 1995 through 1999, inclusive, and 200,000 per year for each year begnning in calendar year 2000, subject to the adjustments noted in the regulations in part 73, subpart E of this chapter.

Authorized account representative means a responsible natural person who is authorized, in accordance with part 73 of this chapter, to transfer and otherwise dispose of allowances held in an Allowance Tracking System general account; or, in the case of a unit account, the designated representative of the owners and operators of the affected unit.

Automated data acquisition and handling system means that component of the CEMS, COMS, or other emissions monitoring system approved by the Administrator for use in the Acid Rain Program, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, opacity monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by part 75 of this chapter.

Award means the conditional set-aside by the Administrator, based on the submission of an early ranking application pursuant to subpart D of this part, of an allowance from the Phase I extension reserve, for possible future allocation to a Phase I extension applicant's Allowance Tracking System unit account.

Baseline means the annual average quantity of fossil fuel consumed by a unit, measured in millions of British Thermal Units (expressed in mmBtu) for calendar years 1985 through 1987; *provided* that in the event that a unit is listed in the NADB, the baseline will be calculated for each unit-generator pair that includes the unit, and the unit's baseline will be the sum of such unit-generator baselines. The unit-generator baseline will be as provided in the NADB under the data field "BASE8587", as adjusted by the outage hours listed in the NADB under the data field "OUTAGEHR" in accordance with the following equation:

$$\text{Baseline}=\text{BASE8587}\times\{26280/(26280-\text{OUTAGEHR})\}\times\{36/(36-\text{months not on line})\}\times 10^{6}$$

"Months not on line" is the number of months during January 1985 through December 1987 prior to the commencement of firing for units that commenced firing in that period, i.e., the number of months, in that period, prior to the on-line month listed under the data field "BLRMNONL" and the on-line year listed in the data field "BLRYRONL" in the NADB.

Basic Phase II allowance allocations

(1) For calendar years 2000 through 2009 inclusive, allocations of allowances made by the Administrator pursuant to section 403 and section 405 (b)(1), (3), and (4); (c)(1), (2), (3), and (5); (d)(1), (2), (4), and (5); (e); (f); (g)(1), (2), (3), (4), and (5); (h)(1); (i); and (j).

(2) For each calendar year beginning in 2010, allocations of allowances made by the Administrator pursuant to section 403 and section 405 (b)(1), (3), and (4); (c)(1), (2), (3), and (5); (d)(1), (2), (4), and (5); (e); (f); (g)(1), (2), (3), (4), and (5); (h)(1) and (3); (i); and (j).

Bias means systematic error, resulting in measurements that will be either consistently low or high relative to the reference value.

Boiler means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or any other medium.

By-pass stack means any duct, stack, or conduit through which emissions from an affected unit may or do pass to the atmosphere, which either augments or substitutes for the principal stack exhaust system or ductwork during any portion of the unit's operation.

Calibration error means the difference between:

(1) The response of gaseous monitor to a calibration gas and the known concentration of the calibration gas;

(2) The response of a flow monitor to a reference signal and the known value of the reference signal; or

(3) The response of a continuous opacity monitoring system to an attenuation filter and the known value of the filter after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

Calibration gas means:

(1) A standard reference material;

(2) A NIST/EPA-approved certified reference material;

(3) A Protocol 1 gas; or

(4) Zero ambient air material.

Capacity factor means the ratio of a unit's actual annual electric output (expressed in Mwe hr) and the unit's nameplate capacity times 8,760 hours.

CEMS precision or precision as applied to the monitoring requirements of part 75 of this chapter, means the closeness of a measurement to the actual measured value expressed as the uncertainty associated with repeated measurements of the same sample or of different samples from the same process (e.g., the random error associated with simultaneous measurements of a process made by more than one instrument). A measurement technique is determined to have increasing "precision" as the variation among the repeated measurements decreases.

Centroidal area means a representational concentric area that is geometrically similar to the stack or duct cross section, and is not greater than 1 percent of the stack or duct cross-sectional area.

Certificate of representation means the completed and signed submission required by § 72.20, for certifying the appointment of a designated representative for an affected source or a group of identified affected sources authorized to represent the owners and operators of such source(s) and of the affected units at such source(s) with regard to matters under the Acid Rain Program.

Certifying official, for purposes of part 73 of this chapter, means:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation;

(2) For partnership or sole proprietorship, a general partner or the proprietor, respectively; and

(3) For a local government entity or State, federal, or other public agency, either a principal executive officer or ranking elected official.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–92 "Standard Classification of Coals by Rank" (as incorporated by reference in § 72.13).

Coal-derived fuel means any fuel, whether in a solid, liquid, or gaseous state, produced by the mechanical, thermal, or chemical processing of coal (e.g., pulverized coal, coal refuse, liquified or gasified coal, washed coal, chemically cleaned coal, coal-oil mixtures, and coke).

Coal-fired means the combustion of fuel consisting of coal or any coal-derived fuel (except a coal-derived gaseous fuel with a sulfur content no greater than natural gas), alone or in combination with any other fuel, where:

(1) For purposes of the requirements of part 75 of this chapter, a unit is "coal-fired" independent of the percentage of coal or coal-derived fuel consumed in any calendar year (expressed in mmBtu); and

(2) For all other purposes under the Acid Rain Program (including for calculating allowance allocations pursuant to part 73 of this chapter and applicability of the requirements of section 407 of the Act), a unit is "coal-fired" if it uses coal or coal-derived fuel as its primary fuel (expressed in mmBtu); *provided* that, if the unit is listed in the NADB, the primary fuel is the fuel listed in the NADB under the data field "PRIMEFUEL".

Cogeneration unit means a unit that has equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) for industrial, commercial, heating or cooling purposes, through the sequential use of energy.

Commence commercial operation means to have begun to generate electricity for sale, including the sale of test generation.

Commence construction means that an owner or operator has either undertaken a continuous program of construction or has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction.

Commence operation means to have begun any mechanical, chemical, or electronic process, including start-up of an emissions control technology or emissions monitor or of a unit's combustion chamber.

Common stack means the exhaust of emissions from two or more units through a single flue.

Compensating unit means a unit that is not otherwise subject to Acid Rain emissions limitation or Acid Rain emissions reduction requirements during Phase I and that is designated as a Phase I unit in a reduced utilization plan under § 72.43; *provided* that a unit that is not an affected unit under the Acid Rain Program shall not be a compensating unit.

Compliance certification means a submission to the Administrator or permitting authority, as appropriate, that is required by this part, by part 73, 75, 77, or 78, or by regulations implementing sections 407 or 410 of the Act to report an affected source or an affected unit's compliance or non-compliance with a provision of the Acid Rain Program and that is signed and verified by the designated representative in accordance with subparts B and I of this part and the Acid Rain Program regulations generally.

Compliance plan, for purposes of the Acid Rain Program, means the document submitted for an affected source in accordance with subpart C of this part, specifying the method(s) (including one or more Acid Rain compliance options under subpart D or regulations implementing section 407 of the Act) by which each affected unit at the source will meet the applicable Acid Rain emissions limitation and Acid Rain emissions reduction requirements.

Compliance subaccount means the subaccount in an affected unit's Allowance Tracking System account, established pursuant to § 73.31 (a) or (b) of this chapter, in which are held, from the date that allowances for the current calendar year are recorded under § 73.34(a) until December 31, allowances available for use by the unit in the current calendar year and, after December 31 until the date that deductions are made under § 73.35(b), allowances available for use by the unit in the preceding calendar year, for the purpose of meeting the unit's Acid Rain emissions limitation for sulfur dioxide.

Compliance use date means the first calendar year for which an allowance may be used for purposes of meeting a unit's Acid Rain emissions limitation for sulfur dioxide.

Conservation Verification Protocol means a methodology developed by the Administrator for calculating the kilowatt hour savings from energy conservation measures and improved unit efficiency measures for the purposes of title IV of the Act.

Construction means fabrication, erection, or installation of a unit or any portion of a unit.

Consumer Price Index or CPI means, for purposes of the Acid Rain Program, the U.S. Department of Labor, Bureau of Labor Statistics unadjusted Consumer Price Index for All Urban Consumers for the U.S. city average, for All Items on the latest reference base, or if such index is no longer published, such other index as the Administrator in his or her discretion determines meets the requirements of the Clean Air Act Amendments of 1990.

(1) *CPI (1990)* means the CPI for all urban consumers for the month of August 1989. The "CPI (1990)" is 124.6 (with 1982–1984=100). Beginning in the month for which a new reference base is established, "CPI (1990)" will be the CPI value for August 1989 on the new reference base.

(2) *CPI (year)* means the CPI for all urban consumers for the month of August of the previous year.

Continuous emission monitoring system or CEMS means the equipment required by part 75 of this chapter used to sample, analyze, measure, and provide, by readings taken at least once every 15 minutes, a permanent record of emissions, expressed in pounds per hour (lb/hr) for sulfur dioxide and in pounds per million British thermal units (lb/mmBtu) for nitrogen oxides. The following systems are component parts included in a continuous emission monitoring system:

(1) Sulfur dioxide pollutant concentration monitor;

(2) Flow monitor;

(3) Nitrogen oxides pollutant concentration monitors;

(4) Diluent gas monitor (oxygen or carbon dioxide);

(5) A continuous moisture monitor when such monitoring is required by part 75 of this chapter; and

(6) A data acquisition and handling system.

Continuous opacity monitoring system or COMS means the equipment required by part 75 of this chapter to sample, measure, analyze, and provide, with readings taken at least once every 6 minutes, a permanent record of opacity or transmittance. The following systems are component parts included

in a continuous opacity monitoring system:

(1) Opacity monitor; and

(2) A data acquisition and handling system.

Control unit means a unit employing a qualifying Phase I technology in accordance with a Phase I extension plan under § 72.42.

Current year subaccount means the subaccount in an Allowance Tracking System general account, established pursuant to § 73.31(c) of this chapter, in which are held allowances that may be transferred to a unit's compliance subaccount for use by the unit for the purpose of meeting its Acid Rain sulfur dioxide emissions limitation.

Customer means a purchaser of electricity not for purposes of transmission or resale.

Decisional body means any EPA employee who is or may reasonably be expected to act in a decision-making role in a proceeding under part 78 of this chapter, including the Administrator, a member of the Environmental Appeals Board, and a Presiding Officer, and any staff of any such person who are participating in the decisional process.

Demand-side measure means a measure:

(1) To improve the efficiency of consumption of electricity from a utility by customers of the utility; or

(2) To reduce the amount of consumption of electricity from a utility by customers of the utility without increasing the use by the customer of fuel other than: Biomass (i.e., combustible energy-producing materials from biological sources, which include wood, plant residues, biological wastes, landfill gas, energy crops, and eligible components of municipal solid waste), solar, geothermal, or wind resources; or industrial waste gases where the party making the submission involved certifies that there is no net increase in sulfur dioxide emissions from the use of such gases. "Demand-side measure" includes the measures listed in part 73, Appendix A, section 1 of this chapter.

Designated representative means a responsible natural person authorized by the owners and operators of an affected source and of all affected units at the source, as evidenced by a certificate of representation submitted in accordance with subpart B of this part, to represent and legally bind each owner and operator, as a matter of federal law, in matters pertaining to the Acid Rain Program. Whenever the term "responsible official" is used in part 70 of this chapter, in any other regulations implementing title V of the Act, or in a State operating permit program, it shall be deemed to refer to the "designated representative" with regard to all matters under the Acid Rain Program.

Diesel fuel means a low sulfur fuel oil of grades 1–D or 2–D, as defined by the American Society for Testing and Materials ASTM D975–91, "Standard Specification for Diesel Fuel Oils" (as incorporated by reference in § 72.13).

Diesel reciprocating engine unit means an internal combustion engine that combusts only diesel fuel and that thereby generates electricity through the operation of pistons, rather than by heating steam or water.

Diluent gas means a major gaseous constituent in a gaseous pollutant mixture, which in the case of emissions from fossil fuel-fired units are carbon dioxide and oxygen.

Diluent gas monitor means that component of the continuous emission monitoring system that measures the diluent gas concentration in a unit's flue gas.

Direct Sale Subaccount means a subaccount in the Special Allowance Reserve, as specified in section 416(b) of the Act, which contains Phase II allowances to be sold in the amount of 25,000 per year, from calendar year 1993 to 1999, inclusive, and of 50,000 per year for each year beginning in calendar year 2000, subject to the adjustments noted in the regulations at part 73, subpart E of this chapter.

Dispatch means the assignment within a dispatch system of generating levels to specific units and generators to effect the reliable and economical supply of electricity, as customer demand rises or falls, and includes:

(1) The operation of high-voltage lines, substations, and related equipment; and

(2) The scheduling of generation for the purpose of supplying electricity to other utilities over interconnecting transmission lines.

Dispatch system means either:

(1) A specified unit and generator or specified group of units, and portions of units, and generators that are interconnected and centrally dispatched, *provided* that the requirements of § 72.33 are met; or

(2) In the event the requirements specified in paragraph (1) of this definition are not met, the unit and generator or group of units and generators that make up one utility system.

Draft Acid Rain permit or draft permit means the version of the Acid Rain permit, or the Acid Rain portion of an operating permit, that a permitting authority offers for public comment.

Dual-fuel reciprocating engine unit means an internal combustion engine that combusts any combination of natural gas and diesel fuel and that thereby generates electricity through the operation of pistons, rather than by heating steam or water.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative and as determined by the Administrator, in accordance with the emissions monitoring requirements of part 75 of this chapter.

Environmental Appeals Board means the three-member board established pursuant to § 1.25(e) of this chapter and authorized to hear appeals pursuant to part 78 of this chapter.

EPA means the United States Environmental Protection Agency.

EPA trial staff means an employee of EPA, whether temporary or permanent, who has been designated by the Administrator to investigate, litigate, and present evidence, arguments, and positions of EPA in any evidentiary hearing under part 78 of this chapter. Any EPA or permitting authority employee, consultant, or contractor who is called as a witness in the evidentiary hearing by EPA trial staff shall be deemed to be "EPA trial staff".

Equivalent diameter means a value, calculated using the equation in paragraph 2.1 of Method 1 in part 60, Appendix A of this chapter, and used to determine the upstream and downstream distances for locating CEMS or CEMS components in flues or stacks with rectangular cross sections.

Ex parte communication means any communication, written or oral, relating to the merits of an adjudicatory proceeding under part 78 of this chapter, that was not originally included or stated in the administrative record, in a pleading, or in an evidentiary hearing or oral argument under part 78 of this chapter, between the decisional body and any interested person outside EPA or any EPA trial staff. Ex parte communication shall not include:

(1) Communication between EPA employees other than between EPA trial staff and a member of the decisional body; or

(2) Communication between the decisional body and interested persons outside the Agency, or EPA trial staff, where all parties to the proceeding have received prior written notice of the proposed communication and are given an opportunity to be present and to participate therein.

Excess emissions means:

(1) Any tonnage of sulfur dioxide emitted by an affected unit during a

calendar year that exceeds the Acid Rain emissions limitation for sulfur dioxide for the unit; and

(2) Any tonnage of nitrogen oxide emitted by an affected unit during a calendar year that exceeds the annual tonnage equivalent of the Acid Rain emissions limitation for nitrogen oxides applicable to the affected unit taking into account the unit's heat input for the year.

Existing unit means a unit (including a unit subject to section 111 of the Act) that commenced commercial operation before November 15, 1990 and that on that date served a generator with a nameplate capacity of greater than 25 MWe. "Existing unit" does not include simple combustion turbines or any unit that on November 15, 1990 served only generators with a nameplate capacity of 25 MWe or less. Any "existing unit" that is modified, reconstructed, or repowered after November 15, 1990 shall continue to be an "existing unit."

Facility means any institutional, commercial, or industrial structure, installation, plant, source, or building.

File means to send or transmit a document, information, or correspondence to the official custody of the person specified to take possession in accordance with the applicable regulation. Compliance with any "filing" deadline shall be determined by the date that person receives the document, information, or correspondence.

Flow meter accuracy means the closeness of the measurement made by a flow meter to the reference value of the fuel flow being measured, expressed as the difference between the measurement and the reference value.

Flow monitor means a component of the continuous emission monitoring system that measures the volumetric flow of exhaust gas.

Flue means a conduit or duct through which gases or other matter are exhausted to the atmosphere.

Forced outage means the removal of a unit from service due to an unplanned component failure or other unplanned condition that requires such removal immediately or within 7 days from the onset of the unplanned component failure or condition. For purposes of §§ 72.43, 72.91, and 72.92, "forced outage" also includes a partial reduction in the heat input or electrical output due to an unplanned component failure or other unplanned condition that requires such reduction immediately or within 7 days from the onset of the unplanned component failure or condition.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means the combustion of fossil fuel or any derivative of fossil fuel, alone or in combination with any other fuel, independent of the percentage of fossil fuel consumed in any calendar year (expressed in mmBtu).

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) as defined by the American Society for Testing and Materials in ASTM D396–90a, "Standard Specification for Fuel Oils" (incorporated by reference in § 72.13), and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid or gaseous state; *provided* that for purposes of the monitoring requirements of part 75 of this chapter, "fuel oil" shall be limited to the petroleum-based fuels for which applicable ASTM methods are specified in Appendices D, E, or F of part 75 of this chapter.

Fuel supply agreement means a legally binding agreement between a new IPP or a firm associated with a new IPP and a fuel supplier that establishes the terms and conditions under which the fuel supplier commits to provide fuel to be delivered to the new IPP.

Future year subaccount means a subaccount in an Allowance Tracking System account, established by the Administrator pursuant to § 73.31 of this chapter, in which allowances are held for one of the 30 years following the later of 1995 or a current calendar year following 1995.

Gas-fired means the combustion of: Natural gas, or a coal-derived gaseous fuel with a sulfur content no greater than natural gas, for at least 90 percent of the average annual heat input during the previous three calendar years and for at least 85 percent of the annual heat input in each of those calendar years; and any fuel other than coal or any other coal-derived fuel for the remaining heat input, if any; *provided* that for purposes of the monitoring exceptions of part 75 of this chapter, the supplemental fuel used in addition to natural gas, if any, shall be limited to gaseous fuels containing no more sulfur than natural gas or, as specified in the monitoring exceptions, fuel oil.

General account means an Allowance Tracking System account that is not a unit account.

Generator means a device that produces electricity and was or would have been required to be reported as a generating unit pursuant to the United States Department of Energy Form 860 (1990 edition).

Hearing clerk means an EPA employee designated by the Administrator to establish a repository for all books, records, documents, and other materials relating to proceedings under part 78 of this chapter.

Heat input means the product (expressed in mmBtu/time) of the gross calorific value of the fuel (expressed in Btu/lb) and the fuel feed rate into the combustion device (expressed in mass of fuel/time) and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Hybrid generation facility means a plant that generates electrical energy derived from a combination of qualified renewable energy (wind, solar, biomass, or geothermal) and one or more other energy resources.

Independent auditor means a professional engineer who is not an employee or agent of the source being audited.

Interested person means any person who submitted written comments or testified at a public hearing on the draft permit or other matter subject to notice and comment under the Acid Rain Program or any person who submitted his or her name to the Administrator or the permitting authority, as appropriate, to be placed on a list of persons interested in such matter. The Administrator or the permitting authority may update the list of interested persons from time to time by requesting additional written indication of continued interest from the persons listed and may delete from the list the name of any person failing to respond as requested.

Investor-owned utility means a utility that is organized as a tax-paying for-profit business.

Kilowatthour saved or *savings* means the net savings in electricity use (expressed in Kwh) that result directly from a utility's energy conservation measures or programs.

Least-cost plan or *least-cost planning process* means an energy conservation and electric power planning methodology meeting the requirements of § 73.82(a)(4) of this chapter.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified generating unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period equal to or greater than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit was built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Mail or serve by mail means to submit or serve by means other than personal service.

Maximum potential NO_x emission rate means the emission rate of nitrogen oxides (in lb/mmBtu) calculated in accordance with section 3 of appendix F of part 75 of this chapter, using the maximum potential nitrogen oxides concentration and either the minimum oxygen concentration (in % O_2) or the maximum carbon dioxide concentration (in % CO_2) as defined in section 2 of appendix A of part 77 of this chapter.

Missing data period means the total number of consecutive hours during which any component part of a certified CEMS or approved alternative monitoring system is not providing quality-assured data, regardless of the reason.

Monitor accuracy means the closeness of the measurement made by a CEMS or by one of its component parts to the reference value of the emissions or volumetric flow being measured, expressed as the difference between the measurement and the reference value.

Monitor operating hour means any hour or portion thereof over which a CEMS, COMS, or other monitoring system approved by the Administrator under part 75 of this chapter is operating regardless of the number of measurements (i.e., data points) collected during the hour.

Most stringent federally enforceable emissions limitation means the most stringent emissions limitation for a given pollutant applicable to the unit, which has been approved by the Administrator under the Act, whether in a State implementation plan approved pursuant to title I of the Act, a new source performance standard, or otherwise. To determine the most stringent emissions limitation for sulfur dioxide, each limitation shall be converted to lbs/mmBtu, using the appropriate conversion factors in appendix B of this part; *provided* that for determining the most stringent emissions limitation for sulfur dioxide for 1985, each limitation shall also be annualized, using the appropriate annualization factors in appendix A of this part.

Multi-header generator means a generator served by ductwork from more than one unit.

Multi-header unit means a unit with ductwork serving more than one generator.

Nameplate capacity means the maximum electrical generating output (expressed in MWe) that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings, as listed in the NADB under the data field "NAMECAP" if the generator is listed in the NADB or as measured in accordance with the United States Department of Energy standards if the generator is not listed in the NADB.

National Allowance Data Base or *NADB* means the data base established by the Administrator under section 402(4)(C) of the Act.

Natural gas means a naturally occurring fluid mixture of hydrocarbons containing little or no sulfur (e.g., methane, ethane, or propane), produced in geological formations beneath the Earth's surface, and maintaining a gaseous state at standard atmospheric temperature and pressure conditions under ordinary conditions.

NERC region means the North American Electric Reliability Council region or, if any, subregion.

Net income neutrality means, in the case of energy conservation measures undertaken by an investor-owned utility whose rates are regulated by a State utility regulatory authority, rates and charges established by the State utility regulatory authority that ensure that the net income earned by the utility on its State-jurisdictional equity investment will be *no lower* as a consequence of its expenditures on cost-effective qualified energy conservation measures and any associated lost sales than it would have been had the utility not made such expenditures, or that the State utility regulatory authority has implemented a ratemaking approach designed to meet this objective.

New independent power production facility or *new IPP* means a unit that:

(1) Commences commercial operation on or after November 15, 1990;

(2) Is nonrecourse project-financed, as defined in 10 CFR part 715;

(3) Sells 80% of electricity generated at wholesale; and

(4) Does not sell electricity to any affiliate or, if it does, demonstrates it cannot obtain the required allowances from such an affiliate.

New unit means a unit that commences commercial operation on or after November 15, 1990, including any such unit that serves a generator with a nameplate capacity of 25 MWe or less or that is a simple combustion turbine.

Ninetieth (90th) percentile means a value that would divide an ordered set of increasing values so that at least 90 percent are less than or equal to the value and at least 10 percent are greater than or equal to the value.

Ninety-fifth (95th) percentile means a value that would divide an ordered set of increasing values so that at least 95 percent of the set are less than or equal to the value and at least 5 percent are greater than or equal to the value.

NIST/EPA-approved certified reference material or NIST/EPA-approved CRM means a calibration gas mixture that has been approved by EPA and the National Institutes of Standards and Technologies (NIST) as having specific known chemical or physical property values certified by a technically valid procedure as evidenced by a certificate or other documentation issued by a certifying standard-setting body.

Offset plan means a plan pursuant to part 77 of this chapter for offsetting excess emissions of sulfur dioxide that have occurred at an affected unit in any calendar year.

Oil-fired means the combustion of: fuel oil for more than 10 percent of the average annual heat input during the previous three calendar years or for more than 15 percent of the annual heat input in any one of those calendar years; and any solid, liquid, or gaseous fuel, other than coal or any other coal-derived fuel (except a coal-derived gaseous fuel with a sulfur content no greater than natural gas), for the remaining heat input, if any; *provided* that for purposes of the monitoring exceptions of part 75 of this chapter, the supplemental fuel used in addition to fuel oil, if any, shall be limited to gaseous fuels, other than a coal-derived fuel.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operating permit means a permit issued under part 70 of this chapter and any other regulations implementing title V of the Act.

Out-of-control period means any period:

(1) Beginning with the hour corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications; and

(2) Ending with the hour corresponding to the completion of an additional calibration error, linearity

check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Oversubscription payment deadline means 30 calendar days prior to the allowance transfer deadline.

Owner means any of the following persons:

(1) Any holder of any portion of the legal or equitable title in an affected unit; or

(2) Any holder of a leasehold interest in an affected unit; or

(3) Any purchaser of power from an affected unit under a life-of-the-unit, firm power contractual arrangement as that term is defined herein and used in section 408(i) of the Act. However, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the affected unit; or

(4) With respect to any Allowance Tracking System general account, any person identified in the submission required by § 73.31(c) of this chapter that is subject to the binding agreement for the authorized account representative to represent that person's ownership interest with respect to allowances.

Owner or operator means any person who is an owner or who operates, controls, or supervises an affected unit or affected source and shall include, but not be limited to, any holding company, utility system, or plant manager of an affected unit or affected source.

Peaking unit means a unit that has:

(1) an average capacity factor of no more than 10 percent during the previous 3 calendar years and

(2) a capacity factor of no more than 20 percent in each of those calendar years.

Permit revision means a permit modification, fast track modification, administrative permit amendment, or automatic permit amendment, as provided in subpart H of this part.

Permitting authority means either

(1) the Administrator in the case of issuance and administration of Acid Rain permits or

(2) the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue proposed Acid Rain permits under subpart G of this part and the other regulations promulgated pursuant to titles IV and V of the Act.

Person includes an individual, corporation, partnership, association, State, municipality, political subdivision of a State, any agency, department, or instrumentality of the United States, and any officer, agent, or employee thereof.

Phase I means the Acid Rain Program period beginning January 1, 1995 and ending December 31, 1999.

Phase I unit means any affected unit that is subject to an Acid Rain emissions reduction requirement or Acid Rain emissions limitation beginning in Phase I.

Phase II means the Acid Rain Program period beginning January 1, 2000, and continuing into the future thereafter.

Phase II unit means any affected unit that is subject to an Acid Rain emissions reduction requirement or Acid Rain emissions limitation during Phase II only.

Pollutant concentration monitor means that component of the continuous emission monitoring system that measures the concentration of a pollutant in a unit's flue gas.

Power distribution system means the portion of an electricity grid owned or operated by a utility that is dedicated to delivering electric energy to customers.

Power sales agreement is a legally-binding agreement between a new IPP or a firm associated with a new IPP and a regulated electric utility that establishes the terms and conditions for the sale of power from the new IPP to the utility.

Presiding Officer means an Administrative Law Judge appointed under 5 U.S.C. 3105 and designated to preside at a hearing in an appeal under part 78 of this chapter or an EPA lawyer designated to preside at any such hearing under § 78.6(b)(3)(ii) of this chapter.

Primary fuel or primary fuel supply means the main fuel type (expressed in mmBtu) consumed by an affected unit for the applicable calendar year.

Proposed Acid Rain permit or proposed permit means, in the case of a State operating permit program, the version of an Acid Rain permit that the permitting authority submits to the Administrator after the public comment period, but prior to completion of the EPA permit review period, as provided for in part 70 of this chapter.

Protocol 1 gas means a calibration gas mixture prepared and analyzed according to the "Procedure for NBS-Traceable Certification of Compressed Gas Working Standards Used for Calibration and Audit of Continuous Emission Monitors ("Revised Traceability Protocol No. 1")," Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III, Stationary Source Specific Methods, Section 3.04, EPA–600/4–77–027b, June 1987 (set forth in Appendix H of part 75 of this chapter).

Qualifying Phase I technology means a technological system of continuous emission reduction that is demonstrated to achieve a ninety (90) percent (or greater) reduction in emissions of sulfur dioxide from the emissions that would have resulted from the use of fossil fuels that were not subject to treatment prior to combustion, as provided in § 72.42.

Qualifying repowering technology means:

(1) Replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of the date of enactment of the Clean Air Act Amendments of 1990; or

(2) Any oil- or gas-fired unit that has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

Quality assured monitor operating hour means any hour over which a certified CEMS, COMS, or other monitoring system approved by the Administrator under part 75 of this chapter, is operating: in accordance with § 75.10(e) and (f); and within the performance specifications set forth in part 75, Appendix A of this chapter and the quality control/quality assurance procedures set forth in part 75, appendix B of this chapter, without unscheduled maintenance, repair, or adjustment.

Receive or receipt of means the date the Administrator or a permitting authority comes into possession of information or correspondence (whether sent in writing or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the information or correspondence, by the Administrator or the permitting authority in the regular course of business.

Recordation, record, or recorded means, with regard to allowances, the transfer of allowances by the

Administrator from one Allowance Tracking System account or subaccount to another.

Reduced utilization means a reduction, during any calendar year in Phase I, in the heat input (expressed in mmBtu for the calendar year) at a Phase I unit below the unit's baseline, where such reduction subjects the unit to the requirement to file a reduced utilization plan under § 72.43.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in part 60, Appendix A of this chapter.

Reference value or reference signal means the known concentration of a calibration gas, the known value of an electronic calibration signal, or the known value of any other measurement standard approved by the Administrator, assumed to be the true value for the pollutant or diluent concentration or volumetric flow being measured.

Relative accuracy means a statistic designed to provide a measure of the systematic and random errors associated with data from continuous emission monitoring systems, and is expressed as the absolute mean difference between the pollutant concentration or volumetric flow measured by the pollutant concentration or flow monitor and the value determined by the applicable reference method(s) plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests in accordance with part 75 of this chapter.

Schedule of compliance means an enforceable sequence of actions, measures, or operations designed to achieve or maintain compliance, or correct non-compliance, with an applicable requirement of the Acid Rain Program, including any applicable Acid Rain permit requirement.

Secretary of Energy means the Secretary of the United States Department of Energy or the Secretary's duly authorized representative.

Serial number means, when referring to allowances, the unique identification number assigned to each allowance by the Administrator, pursuant to § 73.34(d) of this chapter.

Simple combustion turbine means a unit that is a rotary engine driven by a gas under pressure that is created by the combustion of any fuel. This term includes combined cycle units without auxiliary firing but excludes such units with auxiliary firing.

Site lease, as used in part 73, subpart E of this chapter, means a legally-binding agreement signed between a new IPP or a firm associated with a new IPP and a site owner that establishes the terms and conditions under which the new IPP or the firm associated with the new IPP has the binding right to utilize a specific site for the purposes of operating or constructing the new IPP.

Source means any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any regulated air pollutant under the Act. For purposes of section 502(c) of the Act, a "source", including a "source" with multiple units, shall be considered a single "facility."

Span means the range of values that a monitor component is required to be capable of measuring under part 75 of this chapter.

Spot allowance means an allowance that may be used for purposes of compliance with a unit's Acid Rain sulfur dioxide emissions limitation requirements beginning in the year in which the allowance is offered for sale.

Spot Auction means an auction of a spot allowance.

Spot Sale means a sale of a spot allowance.

Stack means a structure that includes one or more flues and the housing for the flues.

Standard conditions means 68 °F at 1 atm (29.92 in. of mercury).

Standard reference material or *SRM* means a calibration gas mixture issued and certified by NIST as having specific known chemical or physical property values.

State means one of the 48 contiguous States and the District of Columbia and includes any non-federal authorities, including local agencies, interstate associations, and State-wide agencies with approved State operating permit programs. The term "State" shall have its conventional meaning where such meaning is clear from the context.

State operating permit program means an operating permit program that the Administrator has approved as meeting the requirements of titles IV and V of the Act, part 70 of this chapter, and this part, including subpart G of this part.

Stationary gas turbine means a turbine that combusts natural gas, coal-derived gaseous fuel with a sulfur content no greater than natural gas, or fuel oil in order to heat inlet combustion air and thereby turn a turbine, in addition to or instead of producing steam or heating water, and that is not self propelled.

Steam sales agreement is a legally-binding agreement between a new IPP or a firm associated with a new IPP and an industrial or commercial establishment requiring steam that sets the terms and conditions under which the new IPP will provide steam to the establishment.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service certified mail with the official postmark or, if service is by the Administrator or the permitting authority, by any other mail service by the United States Postal Service; or

(3) By other means with an equivalent time and date mark used in the regular course of business to indicate the date of dispatch or transmission and a record of prompt delivery. Compliance with any "submission", "service", or "mailing" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Substitute data means emissions or volumetric flow data provided to assure 100 percent recording and reporting of emissions when all or part of the continuous emission monitoring system is not functional or is operating outside applicable performance specifications.

Substitution unit means an affected unit, other than a unit under section 410 of the Act, that is designated as a Phase I unit in a substitution plan under § 72.41.

Sulfur-free generation means: the generation of electricity by a process that does not have any emissions of sulfur dioxide, including hydroelectric, nuclear, solar and wind generation. A "sulfur-free generator" is a generator that produces such "sulfur-free generation."

Supply-side measure means a measure to improve the efficiency of the generation, transmission, or distribution of electricity, implemented by a utility in connection with its operations or facilities to provide electricity to its customers, and includes the measures set forth in part 73, Appendix A, section 2 of this chapter.

Ton or tonnage means any "short ton" (i.e., 2,000 pounds). For the purpose of determining compliance with the Acid Rain emissions limitations and reduction requirements, total tons for a year shall be calculated as the sum of all recorded hourly emissions (or the tonnage equivalent of the recorded hourly emissions rates) in accordance with part 75 of this chapter, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed not to equal any ton.

Transfer unit means a Phase I unit that transfers all or part of its Phase I

emission reduction obligations to a control unit designated pursuant to a Phase I extension plan under § 72.42.

Underutilization means a reduction, during any calendar year in Phase I, of the heat input (expressed in mmBtu for the calendar year) at a Phase I unit below the unit's baseline.

Unit means a fossil fuel-fired combustion device.

Unit account means an Allowance Tracking System account, established by the Administrator for an affected unit pursuant to § 73.31 (a) or (b) of this chapter.

Unit load means the total (i.e., gross) output of a unit or source in any calendar year (or other specified time period) produced by combusting a given heat input of fuel, expressed in terms of:

(1) The total electrical generation (MWe) for use within the plant and for sale; or

(2) In the case of a unit or source that uses part of its heat input for purposes other than electrical generation, the total steam pressure (psia) produced by the unit or source.

Unit operating hours means, when referring to the availability of a monitoring system, the number of hours (or fraction of an hour) that a unit combusts any fuel; and, in the case of a COMS availability, includes the number of hours (or fraction of an hour) after combustion has ceased when fans are operating.

Utility means any person that sells electricity.

Utility competitive bid solicitation is a public request from a regulated utility for offers to the utility for meeting future generating needs. A new IPP may be regarded as having been "selected" in such solicitation pursuant to section 405(g)(6)(A)(iv) of the Act if the utility has named the IPP as a project with which it intends to negotiate a power sales agreement.

Utility regulatory authority means an authority, board, commission, or other entity (limited to the local-, State-, or federal-level, whenever so specified) responsible for overseeing the business operations of utilities located within its jurisdiction, including, but not limited to, utility rates and charges to customers.

Utility system means all interconnected units and generators controlled by the same utility operating company, as reported in the NADB under the data field "UTILNAME".

Utility unit means a unit owned or operated by a utility:

(1) That serves a generator in any State that produces electricity for sale, or

(2) That during 1985, served a generator in any State that produced electricity for sale.

(3) Notwithstanding paragraphs (1) and (2) of this definition, a unit that was in operation during 1985, but did not serve a generator that produced electricity for sale during 1985, and did not commence commercial operation on or after November 15, 1990 is not a utility unit for purposes of the Acid Rain Program.

(4) Notwithstanding paragraphs (1) and (2) of this definition, a unit that cogenerates steam and electricity is not a utility unit for purposes of the Acid Rain Program, unless the unit is constructed for the purpose of supplying, or commences construction after November 15, 1990 and supplies, more than one-third of its potential electrical output capacity and more than 25 MWe output to any power distribution system for sale.

Utilization means the heat input (expressed in mmBtu/time) for a unit.

Volumetric flow means the rate of movement of a specified volume of gas past a cross-sectional area (e.g., cubic feet per hour).

Zero ambient air material means a gas that consists of ambient air and that is vendor-certified to contain: traceable concentrations respectively of SO_2, NO_x, and THC below 0.1 ppm; a concentration of CO below 1 ppm; and a concentration of CO_2 below 400 ppm.

§ 72.3 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

acfh—actual cubic feet per hour.
atm—atmosphere.
bbl—barrel.
Btu—British thermal unit.
°C—degree Celsius (centigrade).
cfm—cubic feet per minute.
cm—centimeter.
dcf—dry cubic feet.
DOE—Department of Energy.
dscf—dry cubic feet at standard conditions.
dscfh—dry cubic feet per hour at standard conditions.
EIA—Energy Information Administration.
eq—equivalent.
°F—degree Fahrenheit.
fps—feet per second.
gal—gallon.
hr—hour.
in—inch.
°K—degree Kelvin.
Kwh—kilowatt hour.
lb—pounds.
m—meter.
mmBtu—million Btu.
min—minute.
mol. wt.—molecular weight.
MWe—megawatt electrical.
MWge—gross megawatt electrical.
ppm—parts per million.
psi—pounds per square inch.
°R—degree Rankine.
scf—cubic feet at standard conditions.
scfh—cubic feet per hour at standard conditions.
sec—second.
std—at standard conditions.
CO_2—carbon dioxide.
NO_x—nitrogen oxides.
O_2—oxygen.
THC—total hydrocarbon content.
SO_2—sulfur dioxide.

§ 72.4 Federal authority.

(a) The Administrator reserves all authority under sections 112(r)(9), 113, 114, 120, 301, 303, 304, 306, and 307(a) of the Act, including, but not limited to, the authority to:

(1) Secure information needed for the purpose of developing, revising, or implementing, or of determining whether any person is in violation of, any standard, method, requirement, or prohibition of the Act, this part, parts 73, 75, 77, and 78 of this chapter, and regulations implementing sections 407 and 410 of the Act;

(2) Make inspections, conduct tests, examine records, and require an owner or operator of an affected unit to submit information reasonably required for the purpose of developing, revising, or implementing, or of determining whether any person is in violation of, any standard, method, requirement, or prohibition of the Act, this part, parts 73, 75, 77, and 78 of this chapter, and regulations implementing sections 407 and 410 of the Act; and

(3) Issue orders, call witnesses, and compel the production of documents.

(b) The Administrator reserves the right under title IV of the Act to take any action necessary to protect the orderly and competitive functioning of the allowance system, including actions to prevent fraud and misrepresentation.

§ 72.5 State authority.

Consistent with section 116 of the Act, the provisions of the Acid Rain Program shall not be construed in any manner to preclude any State from adopting and enforcing any other air quality requirement (including any continuous emissions monitoring) that is not less stringent than, and does not alter, any requirement applicable to an affected unit or affected source under the Acid Rain Program; *provided* that such State requirement, if articulated in an operating permit, is in a portion of the operating permit separate from the

portion containing the Acid Rain Program requirements.

§ 72.6 Applicability.

(a) Each of the following units shall be an affected unit, and any source that includes such a unit shall be an affected source, subject to the requirements of the Acid Rain Program:

(1) A unit listed in Table 1 of § 73.10(a) of this chapter.

(2) An existing unit that is identified as qualifying for an allowance allocation under regulations implementing sections 403 and 405 of the Act and any other existing utility unit, except a unit under paragraph (b) of this section.

(3) A utility unit, except a unit under paragraph (b) of this section, that:

(i) Is a new unit; or

(ii) Did not serve a generator with a nameplate capacity greater than 25 MWe on November 15, 1990 but serves such a generator after November 15, 1990.

(b) The following types of units are not affected units subject to the requirements of the Acid Rain Program:

(1) A simple combustion turbine that commenced operation before November 15, 1990.

(2) Any unit that commenced commercial operation before November 15, 1990 and that did not, as of November 15, 1990, and does not currently, serve a generator with a nameplate capacity of greater than 25 MWe.

(3) Any unit that, during 1985, did not serve a generator that produced electricity for sale and that did not, as of November 15, 1990, and does not currently, serve a generator that produces electricity for sale.

(4) [Reserved: cogeneration units].

(5) [Reserved: qualifying facilities].

(6) [Reserved: new independent power production facilities].

(7) [Reserved: solid waste incinerators].

(8) A non-utility unit.

§ 72.7 New units exemption.

(a) *Applicability.* This section applies to any new utility unit that serves one or more generators with total nameplate capacity of 25 MWe or less and burns only fuels with a sulfur content of 0.05 percent or less by weight, as determined in accordance with paragraph (d)(2) of this section.

(b) *Petition for Written Exemption.* The designated representative, authorized in accordance with subpart B of this part, of a source that includes a unit under paragraph (a) of this section may petition the permitting authority for a written exemption, or to renew a written exemption, for the unit from certain requirements of the Acid Rain Program. The petition shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit.

(2) The nameplate capacity of each generator served by the unit.

(3) A list of all fuels currently burned by the unit and their percentage sulfur content by weight, determined in accordance with paragraph (a) of this section.

(4) A list of all fuels that are expected to be burned by the unit and their sulfur content by weight.

(5) The special provisions in paragraph (d) of this section.

(c) *Permitting Authority's Action.*

(1)(i) The permitting authority shall issue, for any unit meeting the requirements of paragraphs (a) and (b) of this section, a written exemption from the requirements of the Acid Rain Program except for the requirements specified in this section and §§ 72.1 through 72.6 and §§ 72.10 through 72.13; *provided* that no unit shall be exempted unless allowances, equal in number to, and with the same or earlier compliance use date as, all of those allocated under subpart B of part 73 of this chapter for any year for which the unit will be exempted, are deducted from the unit's Allowance Tracking System account.

(ii) The exemption shall take effect on January 1 of the year immediately following the earlier of the date on which the written exemption is issued subject to administrative appeal under part 78 of this chapter or is issued as a final agency action subject to judicial review, in accordance with paragraph (c)(2) of this section; *provided* that the owners and operators, and, to the extent applicable, the designated representative, shall comply with the requirements of the Acid Rain Program concerning all years for which the unit was not exempted, even if such requirements arise, or must be complied with, after the exemption takes effect. The exemption shall not be a defense against any violation of such requirements of the Acid Rain Program whether the violation occurs before or after the exemption takes effect.

(2) In considering and issuing or denying a written exemption under paragraph (c)(1) of this section, the permitting authority shall apply the procedures in subparts F and G of this part and part 70 of this chapter, as applicable, by:

(i) Treating the petition as an Acid Rain permit application under such provisions;

(ii) Issuing or denying a draft written exemption that is treated as the issuance or denial of a draft permit under such provisions; and

(iii) Where the Administrator is the permitting authority, issuing or denying a written exemption that is treated as the issuance or denial of a permit under subpart F of this part or, where a State is the permitting authority, issuing or denying a proposed written exemption that is treated as the issuance or denial of a proposed permit under subpart G of this part and part 70 of this chapter; *provided* that no provision under subparts F and G of this part and part 70 of this chapter concerning the content, effective date, or term of an Acid Rain permit shall apply to the written exemption or proposed written exemption under this section.

(3) A written exemption issued under this section shall have a term of 5 years from its effective date, except as provided in paragraph (d)(4) of this section.

(d) *Special Provisions.* (1) The owners and operators of each unit exempted under this section shall surrender allowances equal in number to, and with the same or an earlier compliance use date as, all of those allocated to the unit under subpart B of part 73 of this chapter for any year for which the unit is exempted and shall waive the right to receive any allowances to be allocated under subpart B of part 73 of this chapter for any year for which the unit is exempted.

(2) The owners and operators of each unit exempted under this section shall determine the sulfur content by weight of its fuel as follows:

(i) For petroleum or petroleum products that the unit burns starting on the first day on which the exemption takes effect until the exemption terminates, a sample of each delivery of such fuel shall be tested using ASTM methods ASTM D4057–88 and ASTM D129–91, ASTM D2622–92, or ASTM D4294–90 (all methods incorporated by reference under § 72.13 of this part.)

(ii) For natural gas that the unit burns starting on the first day on which the exemption takes effect until the exemption terminates, the sulfur content shall be assumed to be 0.05 per cent or less by weight.

(iii) For gaseous fuel (other than natural gas) that the unit burns starting on the first day on which the exemption takes effect until the exemption terminates, a sample of each delivery of such fuel shall be tested using ASTM methods ASTM D1072–90 and ASTM D1265–92 (incorporated by reference under § 72.13 of this part); *provided* that if the gaseous fuel is delivered by pipeline to the unit, a sample of the fuel shall be tested, at least once every

quarter in which the unit operates during any year for which the exemption is in effect, using ASTM method ASTM D1072–90 (incorporated by reference under § 72.13 of this part).

(3) The owners and operators of each unit exempted under this section shall retain at the source that includes the unit, the records of the results of the tests performed under paragraph (d)(2)(i) and (iii) of this section and a copy of the purchase agreements for the fuel under paragraph (d)(2) of this section, stating the sulfur content of such fuel. Such records and documents shall be retained for 5 years from the date they are created.

(4) On the earlier of the date the written exemption expires, the date a unit exempted under this section burns any fuel with a sulfur content in excess of 0.05 percent by weight (as determined in accordance with paragraph (d)(2) of this section), or 24 months prior to the date the unit first serves one or more generators with total nameplate capacity in excess of 25 MWe, the unit shall no longer be exempted under this section and shall be subject to all requirements of the Acid Rain Program, except that:

(i) Notwithstanding § 72.30 (b) and (c), the designated representative of the source that includes the unit shall submit a complete Acid Rain permit application on the later of January 1, 1998 or the date the unit is no longer exempted under this section.

(ii) For purposes of applying monitoring requirements under part 75 of this chapter, the unit shall be treated as a new unit that commenced commercial operation on the date the unit no longer meets the requirements of paragraph (a) of this section.

§ 72.8 Retired units exemption.

(a) *Applicability.* This section applies to any affected unit that is retired prior to the issuance (including renewal) of a Phase II Acid Rain permit for the unit as a final agency action.

(b) *Petition for Written Exemption.* (1) The designated representative, authorized in accordance with subpart B of this part, of a source that includes a unit under paragraph (a) of this section may petition the permitting authority for a written exemption, or to renew a written exemption, for the unit from certain requirements of this part.

(2) A petition under this section shall be submitted on or before:

(i) The deadline for submitting an Acid Rain permit application for Phase II; or

(ii) If the unit has a Phase II Acid Rain permit, the deadline for reapplying for such permit.

(3) The petition under this section shall include the following elements in a format prescribed by the Administrator:

(i) Identification of the unit.

(ii) The applicable deadline under paragraph (b)(2) of this section.

(iii) The actual or expected date of retirement of the unit.

(iv) The following statement: "I certify that this unit ['is' or 'will be', as applicable] permanently retired on the date specified in this petition and will not emit any sulfur dioxide or nitrogen oxides after such date."

(v) A description of any actions that have been or will be taken and provide the basis for the certification in paragraph (b)(3)(iv) of this section.

(iv) The special provisions in paragraph (d) of this section.

(c) *Permitting Authority's Action.* (1)(i) The permitting authority shall issue, for any unit meeting the requirements of paragraphs (a) and (b) of this section, a written exemption from the requirements of this part except for the requirements specified in this section and §§ 72.1 through 72.6 and §§ 72.10 through 72.13.

(ii) The exemption shall take effect on January 1 of the year following the earlier of the date on which the written exemption is issued subject to administrative appeal under part 78 of this chapter or is issued as a final agency action subject to judicial review, in accordance with paragraph (c)(2) of this section; *provided* that the owners and operators, and, to the extent applicable, the designated representative, shall comply with the requirements of this part concerning all years for which the unit was not exempted, even if such requirements arise or must be complied with after the exemption takes effect. The exemption shall not be a defense against any violation of such requirements of the Acid Rain Program whether the violation occurs before or after the exemption takes effect.

(2) In considering and issuing or denying a written exemption under paragraph (c)(1) of this section, the permitting authority shall apply the procedures in subparts F and G of this part and part 70 of this chapter, as applicable, by:

(i) Treating the petition as an Acid Rain permit application under such provisions;

(ii) Issuing or denying a draft written exemption that is treated as the issuance or denial of a proposed permit under such provisions; and

(iii) Where the Administrator is the permitting authority, issuing or denying a written exemption that is treated as a permit under subpart F of this part or, where a State is the permitting authority, issuing or denying a proposed written exemption that is treated as a proposed permit under subpart G of this part and part 70 of this chapter; *provided* that no provision under subparts F and G of this part and part 70 of this chapter concerning, the content, effective date, or term of an Acid Rain permit shall apply to the written exemption or proposed written exemption under this section.

(3) A written exemption issued under this section shall have a term of 5 years, except as provided in paragraph (d)(3) of this section.

(d) *Special Provisions.* (1) A unit exempted under this section shall not emit any sulfur dioxide and nitrogen dioxide starting on the date it is exempted.

(2) The owners and operators of a unit exempted under this section shall comply with monitoring requirements in accordance with part 75 of this chapter and will be allocated allowances in accordance with part 73 of this chapter.

(3) A unit exempted under this section shall not resume operation unless the designated representative of the source that includes the unit submits an Acid Rain permit application for the unit not less than 24 months prior to the later of January 1, 2000 or the date the unit is to resume operation. On the earlier of the date the written exemption expires or the date an Acid Rain permit application is submitted or is required to be submitted under this paragraph, the unit shall no longer be exempted under this section and shall be subject to all requirements of this part.

§ 72.9 Standard requirements.

(a) *Permit Requirements.* (1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under this part in accordance with the deadlines specified in § 72.30;

(ii) Submit in a timely manner a complete reduced utilization plan if required under § 72.43; and

(iii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit.

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

(b) *Monitoring Requirements.* (1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in part 75 of this chapter and section 407 of the Act and regulations implementing section 407 of the Act.

(2) The emissions measurements recorded and reported in accordance with part 75 of this chapter and section 407 of the Act and regulations implementing section 407 of the Act shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of part 75 of this chapter and regulations implementing section 407 of the Act shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

(c) *Sulfur Dioxide Requirements.* (1) The owners and operators of each source and each affected unit at the source shall:

(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under § 73.34(c) of this chapter) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and

(ii) Comply with the applicable Acid Rain emissions limitation for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (c)(1) of this section as follows:

(i) Starting January 1, 1995, an affected unit under § 72.6(a)(1);

(ii) Starting on or after January 1, 1995 in accordance with §§ 72.41 and 72.43, an affected unit under § 72.6(a) (2) or (3) that is a substitution or compensating unit;

(iii) Starting January 1, 2000, an affected unit under § 72.6(a)(2) that is not a substitution or compensating unit; or

(iv) Starting on the later of January 1, 2000 or the deadline for monitor certification under part 75 of this chapter, an affected unit under § 72.6(a)(3) that is not a substitution or compensating unit.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted, in order to comply with the requirements under paragraph (c)(1)(i) of this section, prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under §§ 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

(d) *Nitrogen Oxides Requirements.* The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

(e) *Excess Emissions Requirements.* (1) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under part 77 of this chapter.

(2) The owners and operators of an affected unit that has excess emissions in any calendar year shall:

(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by part 77 of this chapter; and

(ii) Comply with the terms of an approved offset plan, as required by part 77 of this chapter.

(f) *Recordkeeping and Reporting Requirements.* (1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority.

(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with § 72.24; *provided* that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative.

(ii) All emissions monitoring information, in accordance with part 75 of this chapter.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program.

(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under subpart I of this part and part 75 of this chapter.

(g) *Liability.* (1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or a written exemption under § 72.7 or § 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.

(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.

(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as

provided under § 72.41 (substitution plans), § 72.42 (Phase I extension plans), § 72.43 (reduced utilization plans), § 72.44 (Phase II repowering extension plans), and section 407 of the Act and regulations implementing section 407 of the Act, and except with regard to the requirements applicable to units with a common stack under part 75 of this chapter (including §§ 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.

(7) Each violation of a provision of this part, parts 73, 75, 77, and 78 of this chapter, and regulations implementing sections 407 and 410 of the Act by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

(h) *Effect on Other Authorities.* No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or a written exemption under § § 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans.

(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act.

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law.

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act.

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

§ 72.10 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under the Acid Rain Program shall be governed by part 2 of this chapter.

§ 72.11 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the Acid Rain Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the Acid Rain Program, to begin before the occurrence of an act or event shall be computed so that the period ends on the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the Acid Rain Program, falls on a weekend or a federal holiday, the time period shall be extended to the next business day.

(d) Whenever a party or interested person has the right, or is required, to act under the Acid Rain Program within a prescribed time period after service of notice or other document upon him or her by mail, 3 days shall be added to the prescribed time.

§ 72.12 Administrative Appeals.

The procedures for appeals of decisions of the Administrator under this part are contained in part 78 of this chapter.

§ 72.13 Incorporation by reference.

The materials listed in this section are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. These materials are incorporated as they existed on the date of approval, and a notice of any change in these materials will be published in the **Federal Register**. The materials are available for purchase at the corresponding address noted below and are available for inspection at the Office of the Federal Register, 800 N. Capitol Street, NW., Washington, DC, at the Public Information Reference Unit of the U.S. EPA, 401 M Street SW, Washington, DC and at the Library (MD–35), U.S. EPA, Research Triangle Park, North Carolina.

(a) The following materials are available for purchase from the following addresses: American Society for Testing and Material (ASTM), 1916 Race Street, Philadelphia, Pennsylvania 19103; and the University Microfilms International 300 North Zeeb Road, Ann Arbor, Michigan 48106.

(1) ASTM D129–91, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), for § 72.7 of this chapter.

(2) ASTM D388–92, Standard Classification of Coals by Rank for § 72.2 of this chapter.

(3) ASTM D396–90a, Standard Specification for Fuel Oils, for § 72.2 of this chapter.

(4) ASTM D975–91, Standard Specification for Diesel Fuel Oils, for § 72.2 of this chapter.

(5) ASTMD1072–90, Standard Test Method for Total Sulfur in Fuel Gases, for § 72.7 of this chapter.

(6) ASTMD1265–92, Standard Practice for Sampling Liquified Petroleum (LP) Gases (Manual Method), for § 72.7 of this chapter.

(7) ASTM D2622–92, Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry, for § 72.7 of this chapter.

(8) ASTM D 4057–88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, for § 72.7 of this chapter.

(9) ASTM D4294–90, Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy, for § 72.7 of this chapter.

Subpart B—Designated Representative

§ 72.20 Authorization and responsibilities of the designated representative.

(a) Except as provided under § 72.22, each affected source, including all affected units at the source, shall have one and only one designated representative, with regard to all matters under the Acid Rain Program concerning the source or any affected unit at the source.

(b) Upon receipt by the Administrator of a complete certificate of representation, the designated representative of the source shall represent and, by his or her actions, inactions, or submissions, legally bind each owner and operator of the affected source represented and each affected unit at the source in all matters pertaining to the Acid Rain Program, not withstanding any agreement between the designated representative and such owners and operators. The owners and operators shall be bound by any order issued to the designated representative by the Administrator, the permitting authority, or a court.

(c) The designated representative shall be selected and act in accordance with the certifications set forth in § 72.24(a) (4), (5), (7), and (9).

(d) No Acid Rain permit shall be issued to an affected source, nor shall any allowance transfer be recorded for an Allowance Tracking System account of an affected unit at a source, until the Administrator has received a complete

certificate of representation for the designated representative of the source and the affected units at the source.

§ 72.21 Submissions.

(a) Each submission under the Acid Rain Program shall be submitted, signed, and certified by the designated representative for all sources on behalf of which the submission is made.

(b) In each submission under the Acid Rain Program, the designated representative shall certify, by his or her signature:

(1) The following statement, which shall be included verbatim in such submission: "I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made."

(2) The following statement, which shall be included verbatim in such submission: "I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(c) The Administrator and the permitting authority shall accept or act on a submission made on behalf of owners or operators of an affected source and an affected unit only if the submission has been made, signed, and certified in accordance with paragraphs (a) and (b) of this section.

(d) (1) The designated representative of a source shall serve notice on each owner and operator of the source and of an affected unit at the source:

(i) By the date of submission, of any Acid Rain Program submissions by the designated representative and

(ii) Within 10 business days of receipt of a determination, of any written determination by the Administrator or the permitting authority,

(iii) Provided that the submission or determination covers the source or the unit.

(2) The designated representative of a source shall provide each owner and operator of an affected unit at the source a copy of any submission or determination under paragraph (d)(1) of this section, unless the owner or operator expressly waives the right to receive such a copy.

(e) The provisions of this section shall apply to a submission made under parts 73, 75, 77, and 78 of this chapter and under regulations implementing sections 407 and 410 of the Act only if it is made or signed, or required to be made or signed in accordance with parts 73, 75, 77, and 78 of this chapter and regulations implementing sections 407 and 410 of the Act, by:

(i) The designated representative; or

(ii) The authorized account representative or alternate authorized account representative of a unit account.

§ 72.22 Alternate designated representative.

(a) The certificate of representation may designate one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation that meets the requirements of § 72.24 (including those applicable to the alternate designated representative), any action, representation, or failure to act by the alternate designated representative shall be deemed to be an action, representation, or failure to act by the designated representative.

(c) In the event of a conflict, any action taken by the designated representative shall take precedence over any action taken by the alternate designated representative if, in the Administrator's judgement, the actions are concurrent and conflicting.

(d) Except in this section, § 72.23, and § 72.24, whenever the term "designated representative" is used under the Acid Rain Program, the term shall be construed to include the alternate designated representative.

§ 72.23 Changing the designated representative, alternate designated representative; changes in the owners and operators.

(a) *Changing the designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation. Notwithstanding any such change, all submissions, actions, and inactions by the previous designated representative prior to the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and on the owners and operators of the source represented and the affected units at the source.

(b) *Changing the alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation. Notwithstanding any such change, all submissions, actions, and inactions by the previous alternate designated representative prior to the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative and on the owners and operators of the source represented and the affected units at the source.

(c) *Changes in the owners and operators.* (1) In the event a new owner or operator of an affected source or an affected unit is not included in the list of owners and operators submitted in the certificate of representation, such new owner or operator shall be deemed to be subject to and bound by the certificate of representation, the submissions, actions, and inactions of the designated representative and any alternative designated representative of the source or unit, and the decisions, actions, and inactions of the Administrator and permitting authority, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of an affected unit, including the addition of a new owner or operator, the designated representative or any alternative designated representative shall submit a revision to the certificate of representation amending the list of owners and operators to include the change.

§ 72.24 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the affected source and each affected unit at the source for which the certificate of representation is submitted.

(2) The name, address, and telephone and facsimile numbers of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the affected source and of each affected unit at the source and all State or local utility regulatory authorities with jurisdiction over each owner.

(4) The following statement: "I certify that I was selected as the 'designated representative' or "alternate designated representative,' as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source."

(5) The following statement: "I certify that I have given notice of the agreement, selecting me as the 'designated representative' or "alternate designated representative,' as applicable for the affected source and each affected unit at the source identified in this certificate of representation, daily for a period of one week in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice."

(6) The following statement: "I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions."

(7) The following statement: "I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as 'designated representative' or 'alternate designated representative', as applicable."

(8) The following statement: "I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit."

(9) The following statement: "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

(i) "I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and

(ii) "Allowances and proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract."

(10) If there is an alternate designated representative, the following statement: "The agreement by which I was selected as the alternate designated representative includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative."

(11) The signature of the designated representative and any alternate designated representative and the date signed.

(b) Unless otherwise required by the Administrator or the permitting authority, documents of agreement or notice referred to in the certificate of representation shall not be submitted to the Administrator or the permitting authority. Neither the Administrator nor the permitting authority shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 72.25 Objections.

(a) Once a complete certificate of representation has been submitted in accordance with § 72.24, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate is submitted to the Administrator.

(b) Except as provided in § 72.23, no objection or other communication submitted to the Administrator or the permitting authority concerning the authorization, or any submission, action or inaction, of the designated representative shall affect any submission, action, or inaction of the designated representative, or the finality of any decision by the Administrator or permitting authority, under the Acid Rain Program. In the event of such communication, the Administrator and the permitting authority are not required to stay any allowance transfer, any submission, or the effect of any action or inaction under the Acid Rain Program.

(c) Neither the Administrator nor any permitting authority will adjudicate any private legal dispute concerning the authorization or any submission, action, or inaction of any designated representative, including private legal disputes concerning the proceeds of allowance transfers.

Subpart C—Acid Rain Permit Applications

§ 72.30 Requirement to apply.

(a) *Duty to apply.* The designated representative of any source with an affected unit shall submit a complete Acid Rain permit application by the applicable deadline in paragraphs (b) and (c) of this section, and the owners and operators of such source and any affected unit at the source shall not operate the source or unit without a permit that states its Acid Rain program requirements.

(b) *Deadlines.* (1) *Phase I.* (i) The designated representative shall submit a complete Acid Rain permit application governing an affected unit during Phase I to the Administrator on or before February 15, 1993 for:

(A) Any source with such a unit under § 72.6(a)(1); and

(B) Any source with such a unit under § 72.6(a) (2) or (3) that is designated a substitution or compensating unit in a substitution plan or reduced utilization plan submitted to the Administrator for approval or conditional approval.

(ii) Notwithstanding paragraph (b)(1)(i) of this section, if a unit at a source not previously permitted is designated a substitution or compensating unit in a submission requesting revision of an existing Acid Rain permit, the designated representative of the unit shall submit a complete Acid Rain permit application on the date that the submission requesting the revision is made.

(2) *Phase II.* For any source with an existing unit under § 72.6(a)(2), the designated representative shall submit a complete Acid Rain permit application governing such unit during Phase II to the permitting authority on or before January 1, 1996.

(ii) For any source with a new unit under § 72.6(a)(3)(i), the designated representative shall submit a complete Acid Rain permit application governing such unit to the permitting authority at least 24 months before the later of January 1, 2000 or the date on which the unit commences operation.

(iii) For any source with a unit under § 72.6(a)(3)(ii), the designated representative shall submit a complete Acid Rain permit application governing such unit to the permitting authority at least 24 months before the later of January 1,2000 or the date on which the unit begins to serve a generator with a nameplate capacity greater than 25 MWe.

(3) *Acid Rain Compliance Option Deadlines.* The deadlines for applying for approval of any Acid Rain compliance options shall be the

deadlines specified in the relevant section of subpart D of this part and in section 407 of the Act and regulations implementing section 407 of the Act.

(c) *Duty to Reapply.* The designated representative shall submit a complete Acid Rain permit application for each source with an affected unit at least 6 months prior to the expiration of an existing Acid Rain permit governing the unit during Phase II or such longer time as may be approved under part 70 of this chapter that ensures that the term of the existing permit will not expire before the effective date of the permit for which the application is submitted.

(d) The original and three copies of all permit applications for Phase I and where the Administrator is the permitting authority, for Phase II, shall be submitted to the EPA Regional Office for the Region where the affected source is located. The original and three copies of all permit applications for Phase II, where the Administrator is not the permitting authority, shall be submitted to the State permitting authority for the State where the affected source is located.

§ 72.31 Information requirements for Acid Rain permit applications.

A complete Acid Rain permit application shall include following elements in a format prescribed by the Administrator:

(a) Identification of the affected source for which the permit application is submitted;

(b) Identification of each Phase I unit at the source for which the permit application is submitted for Phase I or each Phase II unit at the source for which the permit application is submitted for Phase II;

(c) A complete compliance plan for each unit, in accordance with subpart D of this part;

(d) The standard requirements under § 72.9; and

(e) If the Acid Rain permit application is for Phase II and the unit is a new unit, the date that the unit has commenced or will commence operation and the deadline for monitor certification.

§ 72.32 Permit application shield and binding effect of permit application.

(a) Once a designated representative submits a timely and complete Acid Rain permit application, the owners and operators of the affected source and the affected units covered by the permit application shall be deemed in compliance with the requirement to have an Acid Rain permit under § 72.9(a)(2) and § 72.30(a); *provided* that any delay in issuing an Acid Rain permit is not caused by the failure of the designated representative to submit in a complete and timely fashion supplemental information, as required by the permitting authority, necessary to issue a permit.

(b) Prior to the earlier of the date on which an Acid Rain permit is issued subject to administrative appeal under part 78 of this chapter or is issued as a final agency action subject to judicial review, an affected unit governed by and operated in accordance with the terms and requirements of a timely and complete Acid Rain permit application shall be deemed to be operating in compliance with the Acid Rain Program.

(c) A complete Acid Rain permit application shall be binding on the owners and operators and the designated representative of the affected source and the affected units covered by the permit application and shall be enforceable as an Acid Rain permit from the date of submission of the permit application until the issuance or denial of an Acid Rain permit covering the units and subject to administrative appeal, where the Administrator is the permitting authority, or the issuance or denial of such permit as a final agency action subject to judicial review, where the State is the permitting authority.

§ 72.33 Identification of dispatch system.

(a) Every Phase I unit shall be treated as part of a dispatch system for purposes of § 72.92 in accordance with this section.

(b)(1) The designated representatives of all affected units in a group of all units and generators that are interconnected and centrally dispatched and that are included in the same utility system, holding company, or power pool, may jointly submit to the Administrator a complete identification of dispatch system.

(2) Except as provided in paragraphs (d) and (f) of this section, each Phase I unit may be listed in only one identification of dispatch system.

(3) Any identification of dispatch system must be filed by January 30 of the first year for which the identification is to be in effect.

(c) A complete identification of dispatch system shall include the following elements in a format prescribed by the Administrator:

(1) The name of the dispatch system.

(2) The list of all units and sulfur-free generators in the dispatch system.

(3) The first calendar year for which the identification is to be in effect.

(4) The following statement: "I certify that the units listed herein are and will continue to be interconnected and centrally dispatched, and will be treated as a dispatch system under § 72.92, during the period that this identification of dispatch system is in effect. During such period, all information concerning these units and contained in any submissions under § 72.92 by me and the other designated representatives of these units shall be consistent and shall conform with the data in the dispatch system data reports under § 72.92(b)(2). I understand that if this requirement is not met, then the Administrator will reject all such submissions and treat each unit's utility system as its dispatch system. In such an event, I will make the submissions required under § 72.92 (including a dispatch system data report), treating as the dispatch system the utility system of each unit that I represent."

(5) The signatures of the designated representative for each affected unit in the dispatch system.

(d) In order to change a unit's current dispatch system, complete identifications of dispatch system shall be submitted for the unit's current dispatch system and the unit's new dispatch system, reflecting the change.

(e)(1) Any Phase I unit that is not listed in a complete identification of dispatch shall treat its utility system as its dispatch system.

(2) During the period that the identification of dispatch system is in effect, all information that concerns the units in a given dispatch system and that is contained in any submissions under § 72.92 by designated representatives of these units shall be consistent and shall conform with the data in the dispatch system data reports under § 72.92(b)(2). If this requirement is not met, the Administrator will reject all such submissions, and the designated representatives shall make the submissions under § 72.92 (including the dispatch system data report) treating the utility system of each unit as its dispatch system.

(f)(1) Notwithstanding paragraph (e)(1) of this section or any submission of an identification of dispatch system under paragraphs (b), (c), or (d) of this section, the designated representative of a Phase I unit with two or more owners may petition the Administrator to treat, as the dispatch system for an owner's portion of the unit, the dispatch system of another unit. For purposes of paragraphs (f)(1) through (6) of this section, the owner's portion of the unit shall equal the percentage of that owner's ownership interest in the capacity of the unit.

(2) The petition shall be submitted by January 30 of the first year for which the dispatch system proposed in the petition will take effect, if approved.

The petition shall include the following elements:

(i) The owner's portion of the unit and the other owners' portion(s) of the unit and a demonstration that the sum of all owners' portions of the unit equals 100 percent;

(ii) Documentation demonstrating that the owner's portion specified in the petition equals its ownership interest in the capacity of the unit;

(iii) The name of the proposed dispatch system and documentation demonstrating that the owner's portion of the unit, along with the other units in the proposed dispatch system, are a group of all units and generators that are interconnected and centrally dispatched and that are included in the same utility system, holding company, or power pool.

(iv) The following statement, signed by the designated representatives of all units in the proposed dispatch system: "I certify that the units in the dispatch system proposed in this petition are and will continue to be interconnected and centrally dispatched, and will be treated as a dispatch system under § 72.92, during the period that this petition, as approved, is in effect."

(v) The following statement, signed by the designated representatives of all units in all dispatch systems that will include any portion of the unit if the petition is approved: "During the period that this petition, if approved, is in effect, all information that concerns the units in any dispatch system including any portion of the unit apportioned under the petition and that is contained in any submissions under §§ 72.91 and 72.92 by me and the other designated representatives of these units shall be consistent and shall conform to the data in the dispatch system data reports under § 72.92(b)(2). I am aware of, and will comply with, the requirements imposed under 40 CFR 72.33(f) (4) and (5)."

(3) The Administrator will approve in whole, in part, or with changes or conditions, or deny the petition within 90 days of receipt of the petition. The Administrator will treat the petition, as changed or conditioned upon approval, as amending any identification of dispatch system that is submitted prior to the approval and includes any portion of the unit for which the petition is approved.

(4) The designated representative for the unit for which a petition is approved and the designated representatives of all other units included in all dispatch systems that include any portion of the unit shall submit all annual compliance certification reports, dispatch system data reports, and other reports required under §§ 72.91 and 72.92 treating, as a separate unit, each portion of the unit for which a petition is approved under paragraph (f)(3) of this section and the remaining portion of the unit. The reports shall include all required calculations and demonstrations, treating each such portion of the unit as a separate unit; provided that plan reductions shall be treated in a manner to be determined by the Administrator on a case-by-case basis. The designated representatives shall demonstrate that the data in all the reports under §§ 72.91 and 72.92 has been properly attributed to or apportioned among the owners' portions of the unit and the dispatch systems and that there is no undercounting or double-counting with regard to such data.

(5) In the event that the designated representatives fail to make all the proper attributions, apportionments, calculations, and demonstrations, the Administrator may require that:

(i) All portions of the unit be treated as part of the dispatch system of the unit in accordance with paragraph (e)(1) of this paragraph and any identification of dispatch system submitted under paragraph (b) of this section; and

(ii) The designated representatives make all submissions under §§ 72.91 and 72.92 (including the dispatch system data report) in accordance with paragraph (e)(1) of this paragraph and any identification of dispatch system submitted under paragraph (b) of this section.

(6) Except as expressly provided in paragraphs (f) (1) through (5) of this section or the Administrator's approval of the petition, all provisions of the Acid Rain Program applicable to an affected source or an affected unit shall apply to the entire unit regardless of whether a petition has been submitted or approved, or reports have been submitted, under such paragraphs. Approval of a petition under such paragraphs shall not constitute a determination of the percentage ownership in a unit under any other provision of the Acid Rain Program.

Subpart D—Acid Rain Compliance Plan and Compliance Options

§ 72.40 General.

(a) For each affected unit included in an Acid Rain permit application, a complete compliance plan shall:

(1) For sulfur dioxide emissions, certify that, as of the allowance transfer deadline, the designated representative will hold allowances in the unit's compliance subaccount (after deductions under § 73.34(c) of this chapter) not less than the total annual emissions of sulfur dioxide from the unit. The compliance plan may also specify, in accordance with this subpart, one or more of the Acid Rain compliance options.

(2) For nitrogen oxides emissions, certify that the unit will comply with the applicable limitation established by regulations implementing section 407 of the Act or shall specify one or more Acid Rain compliance options, in accordance with section 407 of the Act and regulations implementing section 407.

(b) *Multi-unit compliance options.* (1) A plan for a compliance option, under § 72.41, 72.42, 72.43, or 72.44 of this part or section 407 of the Act and regulations implementing section 407, that includes units at more than one affected source shall be complete only if:

(i) Such plan is signed and certified by the designated representative for each source with an affected unit governed by such plan; and

(ii) A complete permit application is submitted covering each unit governed by such plan.

(2) A permitting authority's approval of a plan under paragraph (b)(1) of this section that includes units in more than one State shall be final only after every permitting authority with jurisdiction over any such unit has approved the plan with the same modifications or conditions, if any.

(c) *Conditional Approval.* In the compliance plan, the designated representative of an affected unit may propose, in accordance with this subpart, any Acid Rain compliance option for conditional approval, except a Phase I extension plan; *provided* that an Acid Rain compliance option under section 407 of the Act may be conditionally proposed only to the extent provided in regulations implementing section 407 of the Act.

(1) To activate a conditionally-approved Acid Rain compliance option, the designated representative shall notify the permitting authority in writing that the conditionally-approved compliance option will actually be pursued beginning January 1 of a specified year. If the conditionally approved compliance option includes a plan described in paragraph (b)(1) of this section, the designated representative of each source governed by the plan shall sign and certify the notification. Such notification shall be subject to the limitations on activation under subpart D of this part and regulations implementing section 407 of the Act.

(2) The notification under paragraph (c)(1) of this section shall specify the

first calendar year and the last calendar year for which the conditionally approved Acid Rain compliance option is to be activated. A conditionally approved compliance option shall be activated, if at all, before the date of any enforceable milestone applicable to the compliance option. The date of activation of the compliance option shall not be a defense against failure to meet the requirements applicable to that compliance option during each calendar year for which the compliance option is activated.

(3) Upon submission of a notification meeting the requirements of paragraphs (c) (1) and (2) of this section, the conditionally-approved Acid Rain compliance option becomes binding on the owners and operators and the designated representative of any unit governed by the conditionally-approved compliance option.

(4) A notification meeting the requirements of paragraphs (c) (1) and (2) of this section will revise the unit's permit in accordance with § 72.83 (administrative permit amendment).

(d) *Termination of Compliance Option.* (1) The designated representative for a unit may terminate an Acid Rain compliance option by notifying the permitting authority in writing that an approved compliance option will be terminated beginning January 1 of a specified year. If the compliance option includes a plan described in paragraph (b)(1) of this section, the designated representative for each source governed by the plan shall sign and certify the notification. Such notification shall be subject to the limitations on termination under subpart D of this part and regulations implementing section 407 of the Act.

(2) The notification under paragraph (d)(1) of this section shall specify the calendar year for which the termination will take effect.

(3) Upon submission of a notification meeting the requirements of paragraphs (d) (1) and (2) of this section, the termination becomes binding on the owners and operators and the designated representative of any unit governed by the Acid Rain compliance option to be terminated.

(4) A notification meeting the requirements of paragraphs (d) (1) and (2) of this section will revise the unit's permit in accordance with § 72.83 (administrative permit amendment).

§ 72.41 Phase I substitution plans.

(a) *Applicability.* This section shall apply during Phase I to the designated representative of:

(1) Any unit listed in Table 1 of § 73.10(a) of this chapter; and

(2) Any other existing utility unit that is an affected unit under this part, provided that this section shall not apply to a unit under section 410 of the Act.

(b)(1) The designated representative may include, in the Acid Rain permit application for a unit under paragraph (a)(1) of this section, a substitution plan under which one or more units under paragraph (a)(2) of this section are designated as substitution units, provided that:

(i) Any unit under paragraph (a)(2) of this section has the same owner or operator (which includes, for purposes of this section, a designated representative) as the unit under paragraph (a)(1) of this section; and

(ii) In accordance with paragraph (c)(3) of this section, the emissions reductions achieved under the plan shall be the same or greater than would have been achieved by all units governed by the plan without such plan.

(2) The designated representative of each source with a unit designated as a substitution unit in any plan submitted under paragraph (b)(1) of this section shall incorporate in the permit application each such plan.

(3) The designated representative may submit a substitution plan not later than 90 days, or a notification to activate a conditionally approved plan in accordance with § 72.40(c) not later than 60 days, before the allowance transfer deadline applicable to the first year for which the plan is to take effect.

(c) *Contents of a Substitution Plan.* A complete substitution plan shall include the following elements in a format prescribed by the Administrator:

(1) Identification of each unit under paragraph (a)(1) of this section and each substitution unit to be governed by the substitution plan. A unit shall not be a substitution unit in more than one substitution plan.

(2) Except where the designated representative requests conditional approval of the plan, the first calendar year and, if known, the last calendar year in which the substitution plan is to be in effect. Unless the designated representative specifies an earlier calendar year, the last calendar year will be deemed to be 1999.

(3) Calculations to demonstrate that the total emissions reductions achieved under the substitution plan will be equal to or greater than the total emissions reductions that would have been achieved without the plan, as follows:

(i) for each substitution unit:

(A) the unit's baseline.

(B) the lesser of the unit's 1985 actual SO_2 emissions rate or 1985 allowable SO_2 emissions rate.

(C) the product of the baseline in paragraph (c)(3)(i)(A) of this section and the emissions rate in paragraph (c)(3)(i)(B) of this section, divided by 2000 lbs/ton.

(ii) The sum of the amounts in paragraph (c)(3)(i)(C) of this section for all substitution units to be governed by the plan. This sum is the total number of allowances available each year under the substitution plan.

(4) Distribution of substitution allowances.

(i) A statement that the allowances in paragraph (c)(3)(ii) of this section are not to be distributed to any units under paragraph (a)(1) of this section that are to be governed by the plan; or

(ii) A list showing any annual distribution of the allowances in paragraph (c)(3)(ii) of this section from a substitution unit to the unit under paragraph (a)(1) of this section to be governed by the plan. The total number of such allowances allocated among such units each year may not exceed the number calculated under paragraph (c)(3)(ii) of this section.

(5) The special provisions in paragraph (e) of this section.

(d) *Administrator's Action.* (1) If the Administrator approves a substitution plan, he or she will allocate allowances to the Allowance Tracking System accounts of the units under paragraph (a)(1) of this section and substitution units, as provided in the approved plan, upon issuance of an Acid Rain permit containing the plan, except that if the substitution plan is conditionally approved, the allowances will be allocated upon revision of the permit to activate the plan.

(2) In no event shall allowances be allocated, under paragraph (d)(1) of this section, for any year in excess of the amount in paragraph (c)(3)(ii) of this section, as adjusted by the Administrator in approving the plan.

(e) *Special Provisions.*

(1) *Emissions Limitations.* (i) Each substitution unit governed by an approved substitution plan shall become a Phase I unit from January 1 of the year for which the plan takes effect until January 1 of the year for which the plan is no longer in effect or is terminated.

(ii) Each unit under paragraph (a)(1) of this section, and each substitution unit, governed by an approved substitution plan shall be subject to the Acid Rain emissions limitations for nitrogen oxides in accordance with section 407 of the Act and regulations implementing section 407 of the Act.

(2) *Liability.* The owners and operators of a unit governed by an approved substitution plan shall be liable for any violation of the plan or this section at that unit or any other unit that is the first unit's substitution unit or for which the first unit is a substitution unit under the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and section 411 of the Act.

(3) *Termination.* (i) A substitution plan shall be in effect only in Phase I for the calendar years specified in the plan or until the calendar year for which a termination of the plan takes effect, provided that no substitution plan shall be terminated, and no unit shall be de-designated as a substitution unit, before the end of Phase I if the substitution unit serves as a control unit under a Phase I extension plan.

(ii) To terminate a substitution plan for a given calendar year prior to the last year for which the plan was approved:

(A) A notification to terminate in accordance with § 72.40(d) shall be submitted no later than 60 days before the allowance transfer deadline applicable to the given year; and

(B) In the notification to terminate, the designated representative of each unit governed by the plan shall state that he or she surrenders for deduction from the unit's Allowance Tracking System account allowances equal in number to, and with the same or an earlier compliance use date as, those allocated under paragraph (d)(1) of this section for all calendar years for which the plan is to be terminated. The designated representative may identify the serial numbers of the allowances to be deducted. In the absence of such identification, allowances will be deducted on a first-in, first-out basis under § 73.35(c)(2) of this chapter.

(iii) If the requirements of paragraph (e)(2)(ii) of this section are met and upon revision of the permit to terminate the substitution plan, the Administrator will deduct the allowances specified in paragraph (e)(2)(ii)(B) of this section. No substitution plan shall be terminated, and no unit shall be de-designated as a Phase I unit, unless such deduction is made.

(iv) Change of owner or operator. If there is a change in the owners or operators (which includes for purposes of this section the designated representative) of any unit governed by an approved substitution plan and the requirement under paragraph (b)(1)(i) of this section is no longer met, then the designated representatives of the units governed by the plan shall terminate the plan as of January 1 of the calendar year during which the change was made. if the designated representatives fail to terminate the plan, the Administrator, on his own motion, shall terminate the plan and deduct the allowances required to be surrendered under paragraph (e)(2)(ii) of this section.

§ 72.42 Phase I extension plans.

(a) *Applicability.* (1) This section shall apply to any designated representative seeking a 2-year extension of the deadline for meeting Phase I sulfur dioxide emissions reduction requirements at any of the following types of units by applying for allowances from the Phase I extension reserve:

(i) a unit listed in Table 1 of § 73.10(a) of this chapter;

(ii) a unit designated as a substitution unit in accordance with § 72.41; or

(iii) a unit designated as a compensating unit in accordance with § 72.43, except a compensating unit that is a new unit.

(2) A unit for which a Phase I extension is sought shall be either:

(i) A control unit, which shall be a unit under paragraph (a)(1) of this section and at which qualifying Phase I technology shall commence operation on or after November 15, 1990 but not later than December 31, 1996; or

(ii) A transfer unit, which shall be a unit under paragraph (a)(1)(i) of this section and whose Phase I emissions reduction obligation shall be transferred in whole or in part to one or more control units.

(3) A Phase I extension does not exempt the owner or operator for any unit governed by the Phase I extension plan from the requirement to comply with such unit's Acid Rain emissions limitations for sulfur dioxide.

(b) To apply for a Phase I extension:

(1) The designated representative for each source with a control unit may submit an early ranking application for a Phase I extension plan in person, beginning on the 40th day after publication of this subpart in the **Federal Register**, between the hours of 9 a.m. and 5 p.m. Eastern Standard Time at Acid Rain Division, Attn: Early Ranking, U.S. Environmental Protection Agency, 501 3rd Street NW., 4th floor, Washington, DC; or send the application by regular mail, certified mail, or overnight delivery service to Acid Rain Division, Attn: Early Ranking, U.S. Environmental Protection Agency, 6204 J, 401 M Street, SW., Washington, DC 20460.

(2) By February 15, 1993: (i) The designated representative for each source with a control unit shall submit a Phase I extension plan as a part of the Acid Rain permit application for the source, and

(ii) The designated representative for each source with a unit designated as a transfer unit in any plan submitted under paragraph (b)(2)(i) of this section shall incorporate in the Acid Rain permit application each such plan.

(c) *Contents of Early Ranking Application.* A complete early ranking application shall include the following elements in a format prescribed by the Administrator:

(1) Identification of each control unit. All control units in an application must be located at the same source. If the control unit is not a unit under paragraph (a)(1)(i) of this section, a substitution plan or a reduced utilization plan governing the unit shall be submitted by the deadline for submitting a Phase I permit application.

(2) Identification of each transfer unit. A unit shall not be a transfer unit in more than one early ranking application.

(3) For each control and transfer unit, the total tonnage of sulfur dioxide emitted in 1988 plus the total tonnage of sulfur dioxide emitted in 1989, divided by 2. The 1988 and 1989 tonnage figures shall be consistent with the data filed on EIA form 767 for those years and the conversion methodology specified in Appendix B of this part.

(4) For each control and transfer unit:

(i) The projected annual utilization (in mmBtu) for 1995 multiplied by the projected uncontrolled emissions rate (i.e., the emissions rate in the absence of title IV of the Act) for 1995 (in lbs/mmBtu), divided by 2000 lbs/ton.

(ii) The projected annual utilization (in mmBtu) for 1996 multiplied by the projected uncontrolled emissions rate (i.e., the emissions rate in the absence of title IV of the Act) for 1996 (in lbs/mmBtu), divided by 2000 lbs/ton.

(5) For each control and transfer unit, the number of Phase I extension reserve allowances requested for 1995 and for 1996, not to exceed the difference between:

(i) The lesser of the value for the unit under paragraph (c)(3) of this section and the value for the unit for that year under paragraph (c)(4) of this section, and

(ii) Each unit's baseline multiplied by 2.5 lb/mmBtu, divided by 2000 lbs/ton.

(6) Documentation that the annual emissions reduction obligations transferred from all transfer units to all control units do not exceed those authorized under this section, as follows:

(i) For each control unit, the difference, calculated separately for 1995 and 1996, between:

(A) The control unit's allowance allocation in Table 1 of § 73.10(2) of this chapter, the allocation under § 72.41 if the control unit is a substitution unit, or the allocation under § 72.43 if the control unit is a compensating unit; and

(B) The projected emissions resulting from 90% control after installing the qualifying Phase I technology, i.e., 10% of the projected uncontrolled emissions for the control unit for the year in accordance with paragraph (c)(4) of this section.

(ii) The sum, by year, of the results under paragraph (c)(6)(i) of this section for all control units.

(iii) The sum, by year, of Phase I extension reserve allowances requested for all transfer units.

(iv) A showing that, for each year, the sum under paragraph (c)(6)(ii) of this section is greater than or equal to the sum under paragraph (c)(6)(iii) of this section.

(7) For each control and transfer unit, the projected controlled emissions for 1997, for 1998, and for 1999 calculated as follows:

Projected annual utilization (in mmBtu) multiplied by the projected controlled emission rate (in lbs/mmBtu), divided by 2000 lbs/ton.[1]

(8) For each control unit, the number of Phase I extension reserve allowances requested for 1997, for 1998, and for 1999, calculated as follows:

The unit's baseline multiplied by 1.2 lbs/mmBtu and divided by 2000 lbs/ton, minus the projected controlled emissions (in tons/yr) under paragraph (c)(7) of this section for the given year.

(9) The total of Phase I extension reserve allowances requested for all units in the plan for 1995 through 1999.

(10) With regard to each executed contract for the design engineering and construction of qualifying Phase I technology at each control unit governed by the early ranking application, either a copy of the contract or a certification that the contract is on site at the source and will be submitted to the Administrator upon written request. The contract or contracts may be contingent on the Administrator approving the Phase I extension plan.

(11) For each contract for which a certification is submitted under paragraph (c)(10) of this section, a binding letter agreement, signed and dated by each party and specifying:

(i) The type of qualifying Phase I technology to which the contract applies;

(ii) The parties to the contract;

(iii) The date each party executed the contracts;

(iv) The unit to which the contract applies;

(v) A brief list identifying each provision of the contract;

(vi) Any dates to which the parties agree, including construction completion date; and

(vii) The total dollar amount of the contract.

(12) A vendor certification of the sulfur dioxide removal efficiency guaranteed to be achievable by the qualifying Phase I technology for the type and range of fossil fuels (before any treatment prior to combustion) that will be used at the control unit; *provided* that a vendor certification shall not be a defense against a control unit's failure to achieve 90% control of sulfur dioxide.

(13) The date (not later than December 31, 1996) on which the owners and operators plan to commence operation of the qualifying Phase I technology.

(14) The special provisions of paragraph (f) of this section.

(d) *Contents of Phase I Extension Plan.* A complete Phase I extension plan shall include the following elements in a format prescribed by the Administrator:

(1) Identification of each unit in the plan.

(2)(i) A statement that the elements in the Phase I extension plan are identical to those in the previously submitted early ranking application for the plan and that such early ranking application is incorporated by reference; or

(ii) All elements that are different from those in the previously submitted early ranking application for the plan and a statement that the early ranking application is incorporated by reference as modified by the newly submitted elements; *provided* that the Phase I extension plan shall not add any new control units or increase the total Phase I extension allowances requested; or

(iii) All elements required for an early ranking application and a statement that no early ranking application for the plan was submitted.

(e) *Administrator's Action.* (1) *Early ranking applications.* (i) The Administrator may approve in whole or in part or with changes or conditions, as appropriate, or disapprove an early ranking application.

(ii) The Administrator will act on each early ranking application in the order of receipt.

(ii) The Administrator will determine the order of receipt by the following procedures:

(A) Hand-delivered submissions and mailed submissions will be deemed to have been received on the date they are received by the Administrator; *provided* that all submissions received by the Administrator prior to the 40th day after publication of this subpart in the Federal Register will be deemed received on the 40th day.

(B) All submissions received by the Administrator on the same day will be deemed to have been received simultaneously.

(C) The order of receipt of all submissions received simultaneously will be determined by a public lottery if allocation of Phase I extension reserve allowances to each of the simultaneous submissions would result in oversubscription of the Phase I extension reserve.

(iv) Based on the allowances requested under paragraph (c)(9) of this section, as adjusted by the Administrator in approving the early ranking application, the Administrator will award Phase I extension reserve allowances for each complete early ranking application to the extent that allowances that have not been awarded remain in the Phase I extension reserve at the time the Administrator acts on the application. The allowances will be awarded in accordance with the procedures set forth the allocation of reserve allowances in paragraph (e)(3) of this section.

(v) The Administrator's action on an early ranking application shall be conditional on the Administrator's action on a timely and complete Acid Rain permit application that includes a complete Phase I extension plan and, where the plan includes a unit under paragraph (a)(1) (ii) and (iii) of this section, a complete substitution plan or reduced utilization plan, as appropriate.

(vi) Not later than 15 days after receipt of each early ranking application, the Administrator will notify, in writing, the designated representative of each application of the date that the early ranking application was received and one of the following:

(A) The award of allowances if the application was complete and the Phase I extension reserve as not oversubscribed;

(B) A determination that the application was incomplete and is disapproved; or

(C) If the Phase I extension reserve was oversubscribed, a list of the applications received on that date, the number of Phase I extension allowances requested in each application, and the

[1] In the case of a transfer unit that shares a common stack with a unit not listed in Table 1 of § 73.10(a) of this chapter and whose emissions of sulfur dioxide are not monitored separately or apportioned in accordance with part 75 of this chapter, the projected figures for the transfer unit under paragraph (c)(7) of this section must be for the units combined.

date, time, and location of a lottery to determine the order of receipt for all applications received on that date.

(vii) The date of a lottery for all applications received on a given day will not be earlier than 15 days after the Administrator notifies each designated representative whose applications were received on that date.

(viii) Any early ranking application may be withdrawn from the lottery if a letter signed by the designated representative of each unit governed by the application and requesting withdrawal is received by the Administrator before the lottery takes place.

(2) *Phase I extension plans.* (i) The Administrator will act on each Phase I extension plan in the order that the early ranking application for that plan was received or, if no early ranking application was received, in the order that the Phase I extension plan was received, as determined under paragraph (e)(1)(iii) of this section.

(ii) Based on the allowances requested under paragraph (c)(9) of this section, as adjusted under paragraph (d) of this section and by the Administrator in approving the Phase I extension plan, the Administrator will allocate Phase I extension reserve allowances to the Allowance Tracking System account of each control and transfer unit upon issuance of an Acid Rain permit containing the approved Phase I extension plan. The allowances will be allocated using the procedures set forth in paragraph (e)(3) of this section.

(iii) The Administrator will not approve a Phase I extension plan, even if it meets the requirements of this section, unless unallocated allowances remain in the Phase I extension reserve at the time the Administrator acts on the plan.

(3) *Allowance Allocations.* In addition to any allowances allocated in accordance with Table 1 of § 73.10(a) of this chapter and other approved compliance options, the Administrator will allocate Phase I extension reserve allowances to each eligible unit in a Phase I extension plan in the following order.

(i) For 1995, to each control unit in the order in which it is listed in the plan and then to each transfer unit in the order in which it is listed.

(ii) For 1996, to each control unit in the order in which it is listed in the plan and then to each transfer unit in the order in which it is listed.

(iii) For 1997, to each control unit in the order in which it is listed in the plan, then likewise for 1998, and then likewise for 1999.

(iv) The Administrator will allocate any Phase I extension reserve allowances returned to the Administrator to the next Phase I extension plan, in the rank order established under paragraph (e)(1)(iii) of this section, that continues to meet the requirements of this section and this part.

(f) *Special Provisions.* (1) *Emissions Limitations.*

(i) *Sulfur Dioxide.*

(A) If a control or transfer unit governed by an approved Phase I extension plan emits in 1997, 1998, or 1999 sulfur dioxide in excess of the projected controlled emissions for the unit specified for the year under paragraph (c)(7) of this section as adjusted under paragraph (d) of this section and by the Administrator in approving the Phase I extension plan, the Administrator will deduct allowances equal to such exceedence from the unit's annual allowance allocation in the following calendar year.[2]

(B) Failure to demonstrate at least a 90% reduction of sulfur dioxide in 1997, 1998, or 1999 in accordance with part 75 of this chapter at a control unit governed by an approved Phase I extension plan shall be a violation of this section. In the event of any such violation, in addition to any other liability under the Act, the Administrator will deduct allowances from the control unit's compliance subaccount for the year of the violation. The deduction will be calculated as follows:

Allowances deducted=(1−(percent reduction achieved÷90%))×Phase I extension reserve allowances received

where:

"Percent reduction achieved" is the percent reduction determined in accordance with part 75 of this chapter.

"Phase I extension reserve allowances received" is the number of Phase I extension reserve allowances allocated for the year under paragraph (e)(2)(ii) of this section.

(ii) *Nitrogen Oxides.*

(A) Beginning on January 1, 1997, each control and transfer unit shall be subject to the Acid Rain emissions limitations for nitrogen oxides.

(B) Notwithstanding paragraph (f)(1)(ii)(A) of this section, a transfer unit shall be subject to the Acid Rain emissions limitations for nitrogen oxides, under section 407 of the Act and regulations implementing section 407 of the Act, beginning on January 1 of any year for which a transfer unit is allocated fewer Phase I extension reserve allowances than the maximum amount that the designated representative could have requested in accordance with paragraph (c)(5) of this section (as adjusted under paragraph (d) of this section and by the Administrator in approving the Phase I extension plan) unless the transfer unit is the last unit allocated Phase I extension reserve allowances under the plan.

(2) *Monitoring Requirements.* Each control unit shall comply with the special monitoring requirements for Phase I extension plans in accordance with part 75 of this chapter.

(3) *Reporting Requirements.* Each control and transfer unit shall comply with the special reporting requirements for Phase I extension plans in accordance with § 72.93.

(4) *Liability.* The owners and operators of a control or transfer unit governed by an approved Phase I extension plan shall be liable for any violation of the plan or this section at that or any other unit governed by the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and section 411 of the Act.

(5) *Termination.* A Phase I extension plan shall be in effect only in Phase I, and no Phase I extension plan shall be terminated before the end of Phase I. The designated representative may, however, withdraw a Phase I extension plan at any time prior to issuance of the Phase I Acid Rain permit that includes the Phase I extension plan, as adjusted.

§ 72.43 Phase I reduced utilization plans.

(a) *Applicability.* This section shall apply to:

(1) The designated representative of any Phase I unit, including:

(i) Any unit listed in Table 1 of § 73.10(a) of this chapter; and

(ii) Any other unit that becomes a Phase I unit (including any unit designated as a compensating unit under this section or a substitution unit under § 72.41).

(b)(1) The designated representative shall include in the Acid Rain permit application for a Phase I unit a reduced utilization plan, meeting the requirements of this section, when the owners and operators of the unit plan to:

(i) Reduce utilization of the unit below the unit's baseline to achieve compliance, in whole or in part, with the unit's Phase I Acid Rain emissions limitations for sulfur dioxide; and

[2] In the case of a transfer unit that shares a common stack with a unit not listed in Table 1 of § 73.10(a) of this chapter where the units are not monitored separately or apportioned in accordance with part 75 of this chapter, the combined emissions of both units will be deemed to be the transfer unit's emissions for purposes of applying paragraph (f)(1)(i) of this section.

(ii) Accomplish such reduced utilization through one or more of the following:

(A) Shifting generation of the unit to a compensating unit that would not otherwise be a Phase I unit or to a sulfur-free generator; or

(B) Using one or more energy conservation measures or improved unit efficiency measures.

(2)(i) Energy conservation measures shall be either demand-side measures implemented after December 31, 1987 in the residence or facility of a customer to whom the unit's utility system sells electricity or supply-side measures implemented after December 31, 1987 in facilities of the unit's utility system.

(ii) The utility system shall pay in whole or in part for the energy conservation measures either directly or, in the case of demand-side measures, through payment to another person who purchases the measure.

(iii) Energy conservation measures shall not include:

(A) Conservation programs that are exclusively informational or educational in nature;

(B) Load management measures that lead to reduction of electric energy demands during a utility's peak generating period, unless kilowatt hour savings can be verified under § 72.92; or

(C) Utilization of industrial waste gases, unless the designated representative certifies that there is no net increase in sulfur dioxide emissions from such utilization.

(iv) For calendar years when the unit's utility system is a subsidiary of a holding company and the unit's dispatch system is or includes all units that are interconnected and centrally dispatched and included in that holding company, then:

(A) Energy conservation measures shall be either demand-side measures implemented in the residence or facility of a customer to whom any utility system in the holding company sells electricity or supply-side measures implemented in facilities of any utility system in the holding company. Such utility system shall pay in whole or in part for the measures either directly or, in the case of demand-side measures, through payment to another person who purchases the measures.

(B) The limitations in paragraph (b)(2)(iii) of this section shall apply.

(3)(i) Improved unit efficiency measures shall be implemented in the unit. Such measures shall include supply-side measures listed in Appendix A, section 2.1 of part 73 of this chapter.

(ii) The utility system shall pay in whole or in part for the improved unit efficiency measures.

(4) The requirement to submit a reduced utilization plan shall apply in the event that the owners and operators of a Phase I unit decide, at any time during any Phase I calendar year, to rely on the method of compliance in paragraph (b)(1) of this section. In that case, the designated representative shall submit a reduced utilization plan not later than 90 days, or a notification to activate a conditionally approved plan in accordance with § 72.40(c) not later than 60 days, before the allowance transfer deadline applicable to the first year for which the plan is to take effect.

(5) The designated representative of each source with a unit designated as a compensating unit in any plan submitted under paragraphs (b) (1) or (4) of this section shall incorporate by reference in the permit application each such plan.

(c) *Contents of Reduced Utilization Plan.* A complete reduced utilization plan shall include the following elements in a format prescribed by the Administrator:

(1) Identification of each Phase I unit for which the owners and operators plan reduced utilization.

(2) Except where the designated representative requests conditional approval of the plan, the first calendar year and, if known, the last calendar year in which the reduced utilization plan is to be in effect. Unless the designated representative specifies an earlier calendar year, the last calendar year shall be deemed to be 1999.

(3) A statement whether the plan designates a compensating unit or relies on sulfur-free generation, any energy conservation measure, or any improved unit efficiency measure to account for any amount of reduced utilization.

(4) If the plan designates a compensating unit, or relies on sulfur-free generation, to account for any amount of reduced utilization:

(i) Identification of the compensating unit or sulfur-free generator.

(ii) For each compensating unit, the allowance allocation calculated as the compensating unit's baseline multiplied by the lesser of the compensating unit's 1985 actual SO_2 emissions rate or 1985 allowable SO_2 emissions rate, divided by 2000 lbs/ton. If the compensating unit is a new unit, it shall be deemed to have a baseline of zero and shall be allocated no allowances.

(iii) For each sulfur-free generator, identification of any other Phase I units that designate the same sulfur-free generator in another plan submitted under paragraphs (b) (1) or (4) of this section.

(iv) For each compensating unit or sulfur-free generator not in the dispatch system of the unit reducing utilization under the plan, the system directives or power purchase agreements or other contractual agreements governing the purchase of the electrical energy that is generated by the compensating unit or sulfur-free generator and on which the plan relies to accomplish reduced utilization.

(5) The special provisions in paragraph (f) of this section.

(d) *Administrator's Action.* If the Administrator approves the reduced utilization plan, he or she will allocate allowances, as provided in the approved plan, to the Allowance Tracking System accounts for any designated compensating unit upon issuance of an Acid Rain permit containing the plan, except that, if the plan is conditionally approved, the allowances will be allocated upon revision of the permit to activate the plan.

(e) *Failure to Submit a Plan.* (1) The designated representative of a Phase I unit will be deemed not to violate, during a Phase I calendar year, the requirement to submit a reduced utilization plan under paragraph (b) (1) or (4) of this section:

(i) If a unit's adjusted utilization under § 72.91(a) for the year is less than or equal to zero.

(ii) If the unit's adjusted utilization under § 72.91(a) for the year is greater than zero, to the extent that the designated representative complies with the allowance surrender and other requirements of § 72.91 and § 72.92 of this chapter and demonstrates one or more of the following:

(A) The adjusted utilization was offset by adjusted utilization at other Phase I units in the unit's dispatch system;

(B) The adjusted utilization was caused by a dispatch-system-wide sales decline; *provided* that to the extent the percentage of adjusted utilization exceeds the percentage of dispatch-system-wide sales decline, the presumption of this paragraph will be rebuttable and will not apply to the extent the Administrator finds, based on clear and convincing evidence, that the dispatch-system-wide sales decline was not the cause;

(C) The adjusted utilization was caused by a forced outage at the unit; or

(D) The adjusted utilization was caused by economic dispatching that reflected changes in the unit's dispatch order in the dispatch system resulting from increases in the relative cost of generation at the unit (including increases due to the installation of

pollution control equipment or other equipment changes at the unit, the value of allowances saved or avoided, or changes in fuel supply) or by an order of a utility regulatory authority, with rate jurisdiction over an owner of the unit, issued for the purpose of achieving such economic dispatching.

(2) If a Phase I unit's adjusted utilization under § 72.91(a) for a Phase I calendar year is greater than zero and to the extent the demonstrations (if any) made in accordance with paragraph (e)(1) of this section fail to account for any of the adjusted utilization, the Administrator shall determine on a case-by-case basis whether the designated representative of the unit violated the requirement to submit a reduced utilization plan under paragraph (b) (1) or (4) of this section.

(i) Where measures (e.g., the use of low-sulfur coal) were taken at the unit to reduce its emissions rate for the year to 2.5 lbs/mmBtu or less, this will be considered an indicator that the adjusted utilization was not due to a failure to plan.

(ii) Where the adjusted utilization was due to a permanent shutdown of the unit or the owners and operators of the unit did not pursue methods of compliance sufficient to ensure compliance without reduced utilization, this will be considered an indicator of a failure to plan.

(3) Notwithstanding any demonstration or determination under paragraphs (e) (1) and (2) of this section, the designated representative of any Phase I unit shall surrender allowances in accordance with subpart I of this part.

(f) *Special Provisions.* (1) *Emissions Limitations.* (i) Any compensating unit designated under an approved reduced utilization plan shall become a Phase I unit from January 1 of the calendar year in which the plan takes effect until January 1 of the year for which the plan is no longer in effect or is terminated, except that such unit shall not become subject to the Acid Rain emissions limitations for nitrogen oxides in Phase I under section 407 of the Act and regulations implementing section 407 of the Act.

(ii) The designated representative of any Phase I unit (including a unit governed by a reduced utilization plan relying on energy conservation, improved unit efficiency, sulfur-free generation, or a compensating unit) shall surrender allowances, and the Administrator will deduct or return allowances, in accordance with subpart I of this part.

(2) *Reporting Requirements.* The designated representative of any Phase I unit (including a unit governed by a reduced utilization plan relying on energy conservation, improved unit efficiency, sulfur-free generation, or a compensating unit) shall comply with the special reporting requirements under §§ 72.91 and 72.92.

(3) *Liability.* The owners and operators of a unit governed by an approved reduced utilization plan shall be liable for any violation of the plan or this section at that or any other unit governed by the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and section 411 of the Act.

(4) *Termination.* (i) A reduced utilization plan shall be in effect only in Phase I for the calendar years specified in the plan or until the calendar year for which a termination of the plan takes effect; *provided* that no reduced utilization plan that designates a compensating unit that serves as a control unit under a Phase I extension plan shall be terminated, and no such unit shall be de-designated as a compensating unit, before the end of Phase I.

(ii) To terminate a reduced utilization plan for a given calendar year prior to its last year for which the plan was approved:

(A) A notification to terminate in accordance with § 72.40(d) shall be submitted no later than 60 days before the allowance transfer deadline applicable to the given year; and

(B) In the notification to terminate, the designated representative of any compensating unit governed by the plan shall state that he or she surrenders for deduction from the unit's Allowance Tracking System account allowances equal in number to, and with the same or an earlier compliance use date as, those allocated under paragraph (d) of this section to each compensating unit for the calendar years for which the plan is to be terminated. The designated representative may identify the serial numbers of the allowances to be deducted. In the absence of such identification, allowances will be deducted on a first-in, first-out basis under § 73.35(c)(2) of this chapter.

(iii) If the requirements of paragraph (f)(3)(ii) are met and upon revision of the permit to terminate the reduced utilization plan, the Administrator will deduct the allowances specified in paragraph (f)(3)(ii)(B) of this section. No reduced utilization plan shall be terminated, and no unit shall be de-designated as Phase I unit, unless such deduction is made.

§ 72.44 Phase II repowering extensions.

(a) *Applicability.* (1) This section shall apply to the designated representative of:

(i) Any existing affected unit that is a coal-fired unit and has a 1985 actual SO_2 emissions rate equal to or greater than 1.2 lbs/mmBtu.

(ii) Any new unit that will be a replacement unit, as provided in paragraph (b)(2) of this section, for a unit meeting the requirements of paragraph (a)(1)(i) of this section.

(iii) Any oil and/or gas-fired unit that has been awarded clean coal technology demonstration funding as of January 1, 1991 by the Secretary of Energy.

(2) A repowering extension does not exempt the owner or operator for any unit governed by the repowering plan from the requirement to comply with such unit's Acid Rain emissions limitations for sulfur dioxide.

(b) The designated representative of any unit meeting the requirements of paragraph (a)(1)(i) of this section may include in the unit's Phase II Acid Rain permit application a repowering extension plan that includes a demonstration that:

(1) The unit will be repowered with a qualifying repowering technology in order to comply with the Phase II emissions limitations for sulfur dioxide; or

(2) The unit will be replaced by a new utility unit that has the same designated representative and that is located at a different site using a qualified repowering technology and the existing unit will be permanently retired from service on or before the date on which the new utility unit commences commercial operation.

(c) In order to apply for a repowering extension, the designated representative of a unit under paragraph (a) of this section shall:

(1) Submit to the permitting authority, by January 1, 1996, a complete repowering extension plan;

(2) Submit to the Administrator, before June 1, 1997, a complete petition for approval of repowering technology; and

(3) If the repowering extension plan is submitted for conditional approval, submit by December 31, 1997, a notification to activate the plan in accordance with § 72.40(c).

(d) *Contents and Review of Petition for Approval of Repowering Technology* (1) A complete petition for approval of repowering technology shall include the following elements, in a format prescribed by the Administrator, concerning the technology to be used in a plan under paragraph (b) of this section and may follow the repowering

technology demonstration protocol issued by the Administrator:

(i) Identification and description of the technology

(ii) Vendor certification of the guaranteed performance characteristics of the technology, including:

(A) Percent removal and emission rate of each pollutant being controlled;

(B) Overall generation efficiency; and

(C) Information on the state, chemical constituents, and quantities of solid waste generated (including information on land-use requirements for disposal) and on the availability of a market to which any by-products may be sold.

(iii) If the repowering technology is not listed in the definition of a qualified repowering technology in § 72.2, a vendor certification of the guaranteed performance characteristics that demonstrate that the technology meets the criteria specified for non-listed technologies in § 72.2; *provided* that the existence of such guarantee shall not be a defense against the failure to meet the criteria for non-listed technologies.

(2) The Administrator may request any supplemental information that is deemed necessary to review the petition for approval of repowering technology.

(3) The Administrator shall review the petition for approval of repowering technology and, in consultation with the Secretary of Energy, shall make a conditional determination of whether the technology described in the petition is a qualifying repowering technology.

(4) Based on the petition for approval of repowering technology and the information provided under paragraph (d)(2) of this section and § 72.94(a), the Administrator will make a final determination of whether the technology described in the petition is a qualifying repowering technology.

(e) *Contents of Repowering Extension Plan.* A complete repowering extension plan shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the existing unit governed by the plan.

(2) The unit's federally-approved State Implementation Plan sulfur dioxide emissions limitation.

(3) The unit's 1995 actual SO_2 emissions rate.

(4) A schedule for construction, installation, and commencement of operation of the repowering technology approved or submitted for approval under paragraph (d) of this section, with dates for the following milestones:

(i) Completion of design engineering;

(ii) For a plan under paragraph (b)(1) of this section, removal of the existing unit from operation to install the qualified repowering technology;

(iii) Commencement of construction;

(iv) Completion of construction;

(v) Start-up testing;

(vi) For a plan under paragraph (b)(2) of this section, shutdown of the existing unit; and

(vii) Commencement of commercial operation of the repowering technology.

(5) For a plan under paragraph (b)(2) of this section:

(i) Identification of the new unit. A new unit shall not be included in more than one repowering extension plan.

(ii) Certification that the new unit will replace the existing unit.

(iii) Certification that the new unit has the same designated representative as the existing unit.

(iv) Certification that the existing unit will be permanently retired from service on or before the date the new unit commences commercial operation.

(6) The special provisions of paragraph (h) of this section.

(f) *Permitting Authority's Action on Repowering Extension Plan.* (1) The permitting authority shall not approve a repowering extension plan until the Administrator makes a conditional determination that the technology is a qualified repowering technology, unless the permitting authority conditionally approves such plan subject to the conditional determination of the Administrator.

(2) *Permit Issuance.* (i) Upon a conditional determination by the Administrator that the technology to be used in the repowering extension plan is a qualified repowering technology and a determination by the permitting authority that such plan meets the requirements of this section, the permitting authority shall issue the Acid Rain portion of the operating permit including:

(A) The approved repowering extension plan; and

(B) A schedule of compliance with enforceable milestones for construction, installation, and commencement of operation of the repowering technology and other requirements necessary to ensure that Phase II emission reduction requirements under this section will be met.

(ii) Except as otherwise provided in paragraph (g) of this section, the repowering extension shall be in effect starting January 1, 2000 and ending on the day before the date (specified in the Acid Rain permit) on which the existing unit will be removed from operation to install the qualifying repowering technology or will be permanently removed from service for replacement by a new unit with such technology; *provided* that the repowering extension shall end no later than December 31, 2003.

(iii) The portion of the operating permit specifying the repowering extension and other requirements under paragraph (f)(2)(i) of this section shall be subject to the Administrator's final determination, under paragraph (d)(4) of this section, that the technology to be used in the repowering extension plan is a qualifying repowering technology.

(3) *Allowance Allocation.* The Administrator will allocate allowances after issuance of an operating permit containing the repowering extension plan (or, if the plan is conditionally approved, after the revision of the Acid Rain permit under § 72.40(c)) and of the Administrator's final determination, under paragraph (d)(4) of this section, that the technology to be used in such plan is a qualifying repowering technology. Allowances will be allocated (including a pro rata allocation for any fraction of a year), as follows:

(i) To the existing unit under the approved plan, in accordance with section 409(c)(1) of the Act and part 73 of this chapter during the repowering extension under paragraph (f)(2)(ii) of this section; and

(ii) To the existing unit under the approved plan under paragraph (b)(1) of this section or, in lieu of any further allocations to the existing unit, to the new unit under the approved plan under paragraph (b)(2) of this section, in accordance with section 409(c) (2) through (4) of the Act and part 73 of this chapter after the repowering extension under paragraph (f)(2)(ii) of this section ends.

(g) *Failed Repowering Projects.* (1)(i) If, at any time before the end of the repowering extension under paragraph (f)(2)(ii) of this section, the designated representative of a unit governed by an approved repowering extension plan notifies the Administrator in writing that the owners and operators have decided to terminate efforts to properly design, construct, and test the repowering technology specified in the plan before completion of construction or start-up testing and demonstrates, in a proposed permit revision, to the Administrator's satisfaction that such efforts were in good faith, the unit shall not be deemed in violation of the Act because of such a termination. Where the preceding requirements of this paragraph are met, the permitting authority shall revise the operating permit in accordance with this paragraph and paragraph (g)(1)(ii) of this section and § 72.81 (permit modification).

(ii) Regardless of whether notification under paragraph (g)(1)(i) of this section

is given, the repowering extension will end beginning on the earlier of the date of such notification or the date by which the designated representative was required to give such notification under § 72.94(d). The Administrator will deduct allowances (including a pro rata deduction for any fraction of a year) from the Allowance Tracking System account of the existing unit to the extent necessary to ensure that, beginning the day after the extension ends, allowances are allocated in accordance with section 409(c) (2) through (4) of the Act and part 73 of this chapter.

(2) If the designated representative of a unit governed by an approved repowering extension plan demonstrates to the satisfaction of the Administrator, in a proposed permit revision, that the repowering technology specified in the plan was properly constructed and tested on such unit but was unable to achieve the emissions reduction limitations specified in the plan and that it is economically or technologically infeasible to modify the technology to achieve such limits, the unit shall not be deemed in violation of the Act because of such failure to achieve the emissions reduction limitations. In order to be properly constructed and tested, the repowering technology shall be constructed at least to the extent necessary for direct testing of the multiple combustion emissions (including sulfur dioxide and nitrogen oxides) from such unit while operating the technology at nameplate capacity. Where the preceding requirements of this paragraph are met:

(i) The permitting authority shall revise the Acid Rain portion of the operating permit in accordance with paragraphs (g)(2) (ii) and (iii) and § 72.81 (permit modification).

(ii) The existing unit may be retrofitted or repowered with another clean coal or other available control technology.

(iii) The repowering extension will continue in effect until the earlier of the date the existing unit commences commercial operation with such control technology or December 21, 2003. The Administrator will allocate or deduct allowances as necessary to ensure that allowances are allocated in accordance with paragraph (f)(3) of this section applying the repowering extension under this paragraph.

(h) *Special Provisions.* (1) *Emissions Limitations.* (i) *Sulfur Dioxide.* Allowances allocated during the repowering extension under paragraphs (f)(3) and (g)(2)(iii) of this section to a unit governed by an approved repowering extension plan shall not be transferred to any Allowance Tracking System account other than the unit accounts of other units at the same source as that unit.

(ii) *Nitrogen Oxides.* Any existing unit governed by an approved repowering extension plan shall be subject to the Acid Rain emissions limitations for nitrogen oxides in accordance with section 407 of the Act and regulations implementing section 407 of the Act beginning on the date that the unit is removed from operation to install the repowering technology or is permanently removed from service.

(iii) No existing unit governed by an approved repowering extension plan shall be eligible for a waiver under section 111(j) of the Act.

(iv) No new unit governed by an approved repowering extension plan shall receive an exemption from the requirements imposed under section 111 of the Act.

(2) *Reporting Requirements.* Each unit governed by an approved repowering extension plan shall comply with the special reporting requirements of § 72.94.

(3) *Liability.* (i) The owners and operators of a unit governed by an approved repowering plan shall be liable for any violation of the plan or this section at that or any other unit governed by the plan, including liability for fulfilling the obligations specified in part 77 of this chapter an section 411 of the Act.

(ii) The units governed by the plan under paragraph (b)(2) of this section shall continue to have a common designated representative until the existing unit is permanently retired under the plan.

(4) *Terminations.* Except as provided in paragraph (g) of this section, a repowering extension plan shall not be terminated after December 31, 1999.

Subpart E—Acid Rain Permit Contents

§ 72.50 General.

(a) Each Acid Rain permit (including any draft or proposed Acid Rain permit) will contain the following elements in a format prescribed by the Administrator:

(1) All elements required for a complete Acid Rain permit application under § 72.31 of this part, as approved or adjusted by the permitting authority;

(2) The applicable Acid Rain emissions limitation for sulfur dioxide; and

(3) The applicable Acid Rain emissions limitation for nitrogen oxides.

(b) Each Acid Rain permit is deemed to incorporate the definitions of terms under § 72.2 of this part.

§ 72.51 Permit shield.

Each affected unit operated in accordance with the Acid Rain permit that governs the unit and that was issued in compliance with title IV of the Act, as provided in this part and parts 73, 75, 77, and 78 of this chapter, and the regulations implementing section 407 of the Act, shall be deemed to be operating in compliance with the Acid Rain Program, except as provided in § 72.9(g)(6) of this part.

Subpart F—Federal Acid Rain Permit Issuance Procedures

§ 72.60 General.

(a) *Scope.* This subpart contains the procedures for federal issuance of Acid Rain permits for Phase I of the Acid Rain Program and Phase II for sources in States or geographic areas where the Administrator is the permitting authority as provided under regulations implementing title V of the Act. The procedures in this subpart do not apply to the issuance of Acid Rain permits by State permitting authorities with operating permit programs approved under part 70 of this chapter, except as expressly provided in subpart G of this part.

(b) *Permit Decision Deadlines.* The Administrator will issue or deny an Acid Rain permit under § 72.69(a) within 6 months of receipt of a complete Acid Rain permit application submitted for a unit, in accordance with § 72.21, at the U.S. EPA Regional Office for the Region in which the source is located.

§ 72.61 Completeness.

(a) *Determination of Completeness.* The Administrator will determine whether the Acid Rain permit application is complete within 30 days of receipt by the U.S. EPA Regional Office for the Region in which the source is located. The permit application shall be deemed to be complete if the Administrator fails to notify the designated representative to the contrary within 30 days of receipt.

(b) *Supplemental Information.* (1) Regardless of whether the Acid Rain permit application is complete under paragraph (a) of this section, the Administrator may require submission of any additional information that the Administrator determines to be necessary in order to review the Acid Rain permit application and issue an Acid Rain permit.

(2)(i) The designated representative shall submit the information required under paragraph (b)(1) of this section within 30 days after he or she is notified of the requirement for supplemental information unless the Administrator

allows for additional time to collect and submit the information.

(ii) If the designated representative fails to submit the supplemental information within the required time period, the Administrator may disapprove that portion of the Acid Rain permit application for the review of which the information was necessary and may deny the source an Acid Rain permit.

§ 72.62 Draft permit.

(a) After the Administrator receives a complete Acid Rain permit application and any supplemental information, the Administrator will issue a draft permit that incorporates in whole, in part, or with changes or conditions as appropriate, the permit application or deny the source a draft permit.

(b) The draft permit will be based on the information submitted by the designated representative of the affected source and other relevant information.

(c) The Administrator will serve a copy of the draft permit and the statement of basis on the designated representative of the affected source.

(d) The Administrator will provide a 30-day period for public comment, and opportunity to request a public hearing, on the draft permit or denial of a draft permit, in accordance with the public notice required under § 72.65(a)(1)(i) of this part.

§ 72.63 Administrative record.

(a) *Contents of the Administrative Record.* The Administrator will prepare an administrative record for an Acid Rain permit or denial of an Acid Rain permit. The administrative record will contain:

(1) The permit application and any supporting or supplemental data submitted by the designated representative;

(2) The draft permit;

(3) The statement of basis;

(4) Copies of any documents cited in the statement of basis and any other documents relied on by the Administrator in issuing or denying the draft permit (including any records of discussions or conferences with owners, operators, or the designated representative of affected units at the source or interested persons regarding the draft permit), or, for any such documents that are readily available, a statement of their location;

(5) Copies of all written public comments submitted on the draft permit or denial of a draft permit;

(6) The record of any public hearing on the draft permit or denial of a draft permit;

(7) The Acid Rain permit; and

(8) Any response to public comments submitted on the draft permit or denial of a draft permit and copies of any documents cited in the response and any other documents relied on by the Administrator to issue or deny the Acid Rain permit, or, for any such documents that are readily available, a statement of their location.

(b) [Reserved]

§ 72.64 Statement of basis.

(a) The statement of basis will briefly set forth significant factual, legal, and policy considerations on which the Administrator relied in issuing or denying the draft permit.

(b) The statement of basis will include:

(1) The reasons, and supporting authority, for approval or disapproval of any compliance options requested in the permit application, including references to applicable statutory or regulatory provisions and to the administrative record; and

(2) The name, address, and telephone, and facsimile numbers of the EPA office processing the issuance or denial of the draft permit.

§ 72.65 Public notice of opportunities of public comment.

(a)(1) The Administrator will give public notice of the following:

(i) The draft permit or denial of a draft permit and the opportunity for public review and comment and to request a public hearing; and

(ii) Date, time, location, and procedures for any scheduled hearing on the draft permit or denial of a draft permit.

(2) Any public notice given under this section may be for the issuance or denial of one or more draft permits.

(b) *Methods.* The Administrator will give the public notice required by this section by:

(1) Serving written notice on the following persons (except where such person has waived his or her right to receive such notice):

(i) The designated representative;

(ii) The State or local air pollution agency and any State or local utility regulatory authority with jurisdiction over the owners of any source or any unit covered by the Acid Rain permit application;

(iii) The State or local air pollution agency for any contiguous State whose air quality may be affected by, or for any State located within a 50-mile radius of, any source covered by the Acid Rain permit application; and

(iv) Any interested person.

(2) Giving notice by publication in the Federal Register and in a newspaper of general circulation in the area where the source covered by the Acid Rain permit application is located or in a State publication designed to give general public notice.

(c) *Contents.* All public notices issued under this section will contain the following information:

(1) Identification of the EPA office processing the issuance or denial of the draft permit for which the notice is being given.

(2) Identification of the designated representative for the affected source.

(3) Identification of each unit covered by the Acid Rain permit application and the draft permit.

(4) Any compliance options proposed for approval in the draft permit or for disapproval and the total allowances (including any under the compliance options) allocated to each unit if the Acid Rain permit application is approved.

(5) The address and office hours of a public location where the administrative record is available for public inspection and a statement that all information submitted by the designated representative and not protected as confidential under section 114(c) of the Act is available for public inspection as part of the administrative record.

(6) For public notice under paragraph (a)(1)(i) of this section, a brief description of the public comment procedures, including:

(i) A 30-day period for public comment beginning the date of publication of the notice or, in the case of an extension or reopening of the public comment period, such period as the Administrator deems appropriate;

(ii) The address where public comments should be sent;

(iii) Required formats and contents for public comment;

(iv) An opportunity to request a public hearing to occur not earlier than 15 days after public notice is given and the location, date, time, and procedures of any scheduled public hearing; and

(v) Any other means by which the public may participate.

(d) *Extensions and Reopenings of the Public Comment Period.* On the Administrator's own motion or on the request of any person, the Administrator may, at his or her discretion, extend or reopen the public comment period where he or she finds that doing so will contribute to the decision-making process by clarifying one or more significant issues affecting the draft permit or denial of a draft permit. Notice of any such extension or reopening shall be given under paragraph (a)(1)(i) of this section.

§ 72.66 Public comments.

(a) *General.* During the public comment period, any person may submit written comments on the draft permit or the denial of a draft permit.

(b) *Form.* (1) Comments shall be submitted in duplicate.

(2) The submission shall clearly indicate the draft permit issuance or denial to which the comments apply.

(3) The submission shall clearly indicate the name of the person commenting, his or her interest in the matter, and his or her affiliation, if any, to owners and operators of any unit covered by the Acid Rain permit application.

(c) *Contents.* Timely comments on any aspect of the draft permit or denial or a draft permit will be considered unless they concern:

(1) Any standard requirement under § 72.9;

(2) Issues that are not relevant, such as:

(i) The environmental effects of acid rain, acid deposition, sulfur dioxide, or nitrogen oxides generally; and

(ii) Permit issuance procedures, or actions on other permit applications, that are not relevant to the draft permit issuance or denial in question.

(d) Persons who do not wish to raise issues concerning the issuance or denial of the draft permit, but who wish to be notified of any subsequent actions concerning such matter may so indicate in writing during the public comment period or at any other time. The Administrator will place their names on a list of interested persons.

§ 72.67 Opportunity for public hearing.

(a) During the public comment period, any person may request a public hearing. A request for a public hearing shall be made in writing and shall state the issues proposed to be raised in the hearing.

(b) On the Administrator's own motion or on the request of any person, the Administrator may, at his or her discretion, hold a pubic hearing whenever the Administrator finds that such a hearing will contribute to the decision-making process by clarifying one or more significant issues affecting the draft permit or denial of a draft permit. Public hearings will not be held on issues under § 72.66(c) (1) and (2).

(c) During a public hearing under this section, any person may submit oral or written comments concerning the draft permit or denial of a draft permit. The Administrator may set reasonable limits on the time allowed for oral statements and will require the submission of a written summary of each oral statement.

(d) The Administrator will assure that a record is made of the hearing.

§ 72.68 Response to comments.

(a) The Administrator will consider comments on the draft permit or denial of a draft permit that are received during the public comment period and any public hearing. The Administrator is not required to consider comments otherwise received.

(b) In issuing or denying an Acid Rain permit, the Administrator will:

(1) Identify any permit provision or portion of the statement of basis that has been changed and the reasons for the change; and

(2) Briefly describe and respond to relevant comments under paragraph (a) of this section.

§ 72.69 Issuance and effective date of Acid Rain permits.

(a) After the close of the public comment period, the Administrator will issue or deny an Acid Rain permit. The Administrator will serve a copy of any Acid Rain permit and the response to comments on the designated representative for the source covered by the issuance or denial and serve written notice of the issuance or denial on any persons who are entitled to written notice under § 72.65(b)(1) (ii), (iii), and (iv) of this part. The Administrator will also give notice in the **Federal Register.**

(b)(1) The term of every Acid Rain permit shall be 5 years commencing on its effective date.

(2) Every Acid Rain permit for Phase I shall take effect on January 1, 1995.

Subpart G—Acid Rain Phase II Implementation

§ 72.70 Relationship to title V operating permit program.

(a) *Scope.* This subpart sets forth criteria for approval of State operating permit programs and the requirements with which State permitting authorities with approved programs shall comply, and with which the Administrator will comply in the absence of an approved State program, to issue Phase II Acid Rain permits.

(b) *Relationship to Operating Permit Program.* Each State permitting authority with an affected source shall act in accordance with this part and part 70, and part 78 of this chapter for the purpose of incorporating Acid Rain Program requirements into each affected source's operating permit or for issuing written exemptions under §§ 72.7 and 72.8. To the extent that any requirements of this part and part 78 of this chapter are inconsistent with the requirements of part 70 of this chapter, this part and part 78 of this chapter shall take precedence and shall govern the issuance, denial, revision, reopening, renewal, and appeal of the Acid Rain portion of an operating permit. For purposes of applying this subpart, the provisions of this subpart and of part 70 applicable to Acid Rain permit applications and draft, proposed, and final Acid Rain permits shall also apply to petitions for exemption and draft, proposed, and final written exemptions respectively for new or retired units to the extent consistent with §§ 72.7 and 72.8 of this chapter.

§ 72.71 Approval of state programs—general.

(a) Each State shall submit, to the Administrator for approval, a proposed operating permit program meeting the requirements of this subpart and part 70 of this chapter.

(b) The Administrator will act on State submissions of an operating permit program in accordance with the schedule and procedures set forth in § 70.4(e) of this chapter. The Administrator will approve State programs that conform to the applicable requirements of this subpart and § 70.4(b) of this chapter.

(c)(1) After approval of a State operating permit program, the Administrator will suspend, in accordance with this part and part 70 of this chapter, federal issuance of Acid Rain permits for Phase II for sources and units subject to the State program.

(2) The Administrator will issue all Acid Rain permits for Phase I. However, the Administrator reserves the right to delegate the remaining administration of Acid Rain permits for Phase I to approved State operating permit programs.

§ 72.72 State permit program approval criteria.

A State operating permit program shall meet the following criteria concerning the Acid Rain Program. Any aspect of the State program or any implementation of the State program that is inconsistent with these criteria shall be grounds for disapproval or withdrawal of approval of the State program by the Administrator:

(a) *Non-Interference with Acid Rain Program.* The State operating permit program shall not include or implement any measures that would interfere with the Acid Rain Program. In particular, the State program shall not restrict or interfere with allowance trading and shall not interfere with the Administrator's decision on an offset plan. Aspects and implementation of the State program that would constitute interference with the Acid Rain

Program, and are thus prohibited, include but are not limited to:

(1) Prohibitions, inconsistent with the Acid Rain Program, on the acquisition or transfer of allowances by an affected unit under the jurisdiction of the State permitting authority;

(2) Restrictions, inconsistent with the Acid Rain Program, on an affected unit's ability to sell or otherwise obligate its allowances;

(3) Requirements that an affected unit maintain a balance of allowances in excess of the level determined to be prudent by any utility regulatory authority with jurisdiction over the owners of the affected unit;

(4) Failing to notify the Administrator of any State administrative or judicial appeals of, or decisions covering, Acid Rain permit provisions that might affect Acid Rain Program requirements;

(5) Issuing an order, inconsistent with the Acid Rain Program, interpreting Acid Rain Program requirements as not applicable to an affected source or an affected unit in whole or in part or otherwise adjusting the requirements;

(6) Withholding approval of any compliance option that meets the requirements of the Acid Rain Program; or

(7) Any other aspect of implementation that the Administrator determines would hinder the operation of the Acid Rain Program.

(b) The State operating permit program shall require the following:

(1) *Acid Rain Permit Issuance.* Issuance or denial of Acid Rain permits shall follow the procedures under this part and part 70 of this chapter including:

(i) *Permit Application.* (A) *Requirement to Comply.* The owners and operators and the designated representative for each affected source under jurisdiction of the State permitting authority shall be required to comply with subparts B, C, and D of this part.

(B) *Effect of an Acid Rain Permit Application.* A complete Acid Rain permit application shall be binding on the owners and operators and the designated representative of the affected source, all affected units at the source, and any other unit governed by the permit application and shall be enforceable as an Acid Rain permit, from the date of submission of the permit application until the issuance or denial of the Acid Rain permit under paragraph (b)(1)(vii) of this section.

(C) *Submission to the Administrator.* The State permitting authority shall submit a written notice of application completeness to the Administrator within 10 working days following a determination by the State permitting authority that the Acid Rain permit application is complete.

(ii) *Draft Permit.* (A) The State permitting authority shall prepare the draft Acid Rain permit in accordance with subpart E of this part or deny a draft Acid Rain permit.

(B) The State permitting authority shall prepare a statement of basis in accordance with the requirements for a statement of basis under § 72.64 of this part.

(iii) *Notice to Administrator.* The State permitting authority shall submit a copy of the draft Acid Rain permit and the statement of basis to the Administrator and all other relevant portions of the operating permit that may affect the draft Acid Rain permit. This submission requirement will not be waived.

(iv) *Public Notice and Comment Period.* Public notice of the issuance or denial of the draft Acid Rain permit and the opportunity to comment and request a public hearing shall be given by publication in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice. A notice shall be served on those persons required to receive notice under §§ 70.7(h) and 70.8(b) of this chapter.

(v) *Proposed Permit.* Following the public notice and comment period on a draft Acid Rain permit, the permitting authority shall incorporate all changes necessary and issue a proposed Acid Rain permit in accordance with subpart E of this part or deny a proposed Acid Rain permit.

(vi) *Submittal to Administrator.* (A) The State permitting authority shall submit the proposed Acid Rain permit or denial of a proposed Acid Rain permit to the Administrator in accordance with § 70.8(a) of this chapter, the provisions of which shall be treated as applying to the issuance or denial of a proposed Acid Rain permit.

(B) The Administrator will review the proposed Acid Rain permit or denial of a proposed Acid Rain permit in accordance with § 70.8(c) of this chapter, the provisions of which shall be treated as applying to the issuance or denial of a proposed Acid Rain permit.

(vii) *Acid Rain Permit Issuance.* Following the Administrator's review of the proposed Acid Rain permit or denial of a proposed Acid Rain permit, the State permitting authority shall or, under § 70.8(c) of this chapter (treated as applying to the issuance or denial of an Acid Rain permit), the Administrator will, incorporate any required changes and issue or deny the Acid Rain permit in accordance with subpart E of this part.

(viii) *Effective Date of Acid Rain Permit.* Each source's Acid Rain permit issued by a State permitting authority under this section shall be effective for a period of 5 years.

(ix) *New Owners.* An Acid Rain permit shall be binding on any new owner or operator or designated representative of any source or unit governed by the permit.

(x) Each Acid Rain permit (including a draft or proposed permit) shall contain all applicable Acid Rain requirements, shall be a complete and segregable portion of the operating permit, and shall not incorporate information contained in any other documents, other than documents that are readily available.

(xi) Invalidation of the Acid Rain portion of an operating permit shall not affect the continuing validity of the rest of the operating permit, nor shall invalidation of any other portion of the operating permit affect the continuing validity of the Acid Rain portion of the permit.

(xii) No Acid Rain permit (including a draft or proposed permit) shall be issued unless the Administrator has received a certificate of representation for the designated representative of the source in accordance with subpart B of this part.

(xiii) Notwithstanding any State law providing that a permit must be issued by default after a specified time, no Acid Rain permit shall be issued until the Administrator and other States have had an opportunity to review a proposed Acid Rain permit as provided in this section and § 70.8(b) of this chapter.

(xiv) Except as provided in § 72.73(b), the State permitting authority shall issue or deny an Acid Rain permit within 18 months of receiving a complete Acid Rain permit application submitted for an affected unit in accordance with § 72.21 or such lesser time approved under part 70 of this chapter.

(2) *Permit Revisions.* In acting on any Acid Rain permit revision, the State permitting authority shall follow the provisions and procedures set forth at subpart H of this part.

(3) *Permit Renewal.* The renewal of an Acid Rain permit for an affected source shall be subject to all the requirements of this subpart pertaining to the issuance of permits.

(4) *Acid Rain Program Forms.* In developing the Acid Rain portion of the operating permit, the permitting authority shall use the applicable forms or other formats prescribed by the

Administrator under the Acid Rain Program; *provided* that the Administrator may waive this requirement in whole or in part.

(5) *Acid Rain Appeal Procedures.* (i) Appeals of the Acid Rain portion of an operating permit issued by the State permitting authority that do not challenge or involve decisions or actions of the Administrator under this part, parts 73, 75, 77 and 78 of this chapter, and sections 407 and 410 of the Act and regulations implementing sections 407 and 410 shall be conducted according to procedures established by the State under § 70.4(b)(3)(x) of this chapter. Appeals of the Acid Rain portion of such a permit that challenge or involve such decisions or actions of the Administrator shall follow the procedures under part 78 of this chapter and section 307 of the Act. Such decisions or actions include, but are not limited to, allowance allocations, determinations concerning alternative monitoring systems, and determinations of whether a technology is a qualifying repowering technology.

(ii) Under no circumstances shall a State administrative appeal or judicial appeal of the Acid Rain portion of an operating permit be allowed more than 90 days (or such shorter period as provided by the applicable State appeals procedures) following respectively issuance of the Acid Rain portion that is subject to administrative appeal or issuance of the final agency action subject to judicial appeal.

(iii) The State permitting authority shall serve written notice on the Administrator of any State administrative or judicial appeal concerning as Acid Rain provision of any operating permit or denial of an Acid Rain portion of any operating permit within 30 days of the filing of the appeal.

(iv) Any State administrative permit appeals procedures shall ensure that the Administrator may intervene as a matter of right in any permit appeal involving an Acid Rain permit provision or denial of an Acid Rain permit.

(v) The State permitting authority shall serve written notice on the Administrator of any determination or order in a State administrative or judicial proceeding that interprets, modifies, voids, or otherwise relates to any portion of an Acid Rain permit. Following any such determination or order, the Administrator will have an opportunity to review and veto the Acid Rain permit or revoke the permit for cause in accordance with § 70.8 of this chapter.

(vi) A failure of the State permitting authority to issue an Acid Rain permit in accordance with § 72.73(b)(1)(i) shall be ground for filing an appeal.

(vii) No appeal concerning an Acid Rain requirement shall result in a stay of any provision of the Acid Rain permit for which a stay is barred under part 78 of this chapter.

(6) *Cooperation with Utility Regulatory Authority.* In considering any Acid Rain permit application, the State permitting authority shall ensure coordination with any utility regulatory authority with jurisdiction over the owners of the affected unit.

(7) *New Units and Retired Units Exemptions.* The State permitting authority shall act in accordance with §§ 72.7 and 72.8 on any petition for exemption of a new unit or retired unit from requirements of the Acid Rain Program.

(8) *State Permit Evaluation.* The State permitting authority shall periodically evaluate the extent to which its operating permit program meets the Acid Rain Program requirements and supports a cost-effective implementation of the program. The permit fee rates set by the State permitting authority shall be adequate to cover such evaluation.

§ 72.73 State issuance of Phase II permits.

(a) *State Permit Issuance.* (1) A State with an operating permit program that has been approved by the Administrator under this part and part 70 of this chapter on or before July 1, 1996, shall be responsible for issuing Acid Rain permits for Phase II to all affected sources in that State.

(2) A State that has obtained interim operating permit program approval (as defined in § 70.4(d) of this chapter) on or before July 1, 1996 shall be responsible for issuing Acid Rain permits for Phase II to all affected sources in that State.

(3) A State that has obtained partial operating permit program approval (as defined in § 70.4(c) of this chapter) on or before July 1, 1996 shall be responsible for issuing Acid Rain permits for Phase II to all affected sources in the geographic area to which the partial approval applies.

(4) The State permitting authority shall comply with the procedures for issuance, revision, renewal, and appeal of Acid Rain permits under this subpart.

(b) *Permit Issuance Deadline.* (1)(i) On or before December 31, 1997, a State with an approved operating permit program shall issue an Acid Rain permit for Phase II to each affected source in the geographic area for which the program is approved as set forth in paragraph (a) of this section; *provided* that the designated representative of the source submitted a timely and complete Acid Rain permit application in accordance with § 72.21 of this part and meets the requirements of this subpart and part 70 of this chapter.

(ii) Each Acid Rain permit issued in accordance with this section shall have a term of 5 years commencing on its effective date. Each Acid Rain permit issued in accordance with paragraph (b)(1)(i) of this section shall take effect by the later of January 1, 2000, or, where the permit governs a unit under § 72.6(a)(3) of this part, the deadline for monitor certification under part 75 of this chapter.

(2) *Nitrogen Oxides.* Not later than January 1, 1999, the State permitting authority shall reopen the Acid Rain permit to add the Acid Rain Program nitrogen oxides requirements; *provided* that the designated representative of the affected source submitted a timely and complete Acid Rain permit application for nitrogen oxides in accordance with § 72.21. Such reopening shall not affect the term of the Acid Rain portion of an operating permit.

§ 72.74 Federal issuance of Phase II permits.

(a) The Administrator will be responsible for issuing Acid Rain permits for Phase II for any affected sources in a geographic area (including a State) that does not have an operating permit program with full, partial, or interim approval by the Administrator on or before July 1, 1996, under part 70 of this chapter. After approval of a State program, the Administrator will suspend, in accordance with this part and part 70 of this chapter, federal issuance of such permits for sources in the geographic area covered by the State program and the State shall be responsible for issuing such permits in accordance with § 72.73 of this part.

(b) *Permit Issuance Deadline.* (1)(i) On or before January 1, 1998, the Administrator will issue an Acid Rain permit for Phase II governing Acid Rain Program sulfur dioxide requirements to each affected source in a geographic area that, on July 1, 1996, did not have an approved operating permit program under part 70 of this chapter; *provided* that the designated representative for the source submitted a timely and complete Acid Rain permit application in accordance with § 72.21 of this part. The failure by the Administrator to issue a permit in accordance with this paragraph shall be grounds for the filing of an appeal under part 78 of this chapter.

(ii) Notwithstanding paragraph (b)(1)(i) of this section, the Administrator may delegate to any State

that obtains operating permit program approval after July 1, 1996, responsibility for permit review and implementation.

(iii) Each Acid Rain permit issued in accordance with this section shall have a term of 5 years commencing on its effective date. Each Acid Rain permit issued in accordance with paragraph (b)(1) shall take effect by the later of January 1, 2000 or, where a permit governs a under § 72.6(a)(3) of this part, the deadline for monitor certification under part 75 of this chapter.

(2) *Nitrogen Oxides.* Not later than 6 months following submission by the designated representative of a timely and complete Acid Rain permit application for nitrogen oxides, the Administrator shall reopen the Acid Rain permit for Phase II to add the Acid Rain Program nitrogen oxides requirements. Such reopening shall not affect the term of the Acid Rain permit.

(c) *Permit Issuance.* The Administrator will issue Acid Rain permits for Phase II in accordance with subparts E and F of this part and the regulations implementing title V of the Act.

Subpart H—Permit Revisions

§ 72.80 General.

(a) This subpart shall govern revisions to any Acid Rain permit issued by the Administrator and to the Acid Rain portion of any operating permit issued by a State with an approved operating permit program under part 70 of this chapter.

(b) The provisions of this subpart shall supersede the operating permit revision procedures specified in part 70 of this chapter with regard to revision of any Acid Rain Program permit provision.

(c) A permit revision may be submitted for approval at any time. No permit revision shall affect the term of the Acid Rain permit to be revised. No permit revision shall excuse any violation of an Acid Rain Program requirement that occurred prior to the effective date of the revision.

(d) The terms of the Acid Rain permit shall apply while the permit revision is pending.

(e) Any determination or interpretation by a State (including a State court) modifying or voiding any Acid Rain permit provision shall be subject to review by the Administrator in accordance with § 70.8(c) of this chapter as applied to permit modifications, unless the determination or interpretation is an administrative amendment approved in accordance with § 72.83 of this part.

(f) The standard requirements of § 72.9 of this part shall not be modified or voided by a permit revision.

(g) Any permit revision involving incorporation of a compliance option that was not submitted for approval and comment during the permit issuance process, or involving a change in a compliance option that was previously submitted, shall meet the requirements for applying for such compliance option under subpart D and section 407 of the Act and regulations implementing section 407 of the Act.

(h) For permit revisions not described in §§ 72.81 and 72.82 of this part, the permitting authority may, in its discretion, determine which of these sections is applicable.

§ 72.81 Permit modifications.

(a) Permit revisions that shall follow the permit modification procedures are:

(1) Relaxation of an excess emission offset requirement after approval of the offset plan by the Administrator;

(2) Incorporation of a final nitrogen oxides alternative emission limitation following a demonstration period;

(3) Determinations concerning failed repowering projects under § 72.44(g)(1)(i) and (2) of this part.

(b) The following permit revisions shall follow, at the option of the designated representative submitting the permit revision, either the permit modification procedures or the fast-track modification procedures under § 72.82 of this part:

(1) Consistent with paragraph (a) of this section, incorporation of a compliance option that the designated representative did not submit for approval and comment during the permit issuance process; except that incorporation of a reduced utilization plan that was not submitted during the permit issuance process, that does not designate a compensating unit, and that meets the requirements of § 72.43 of this part, may use the administrative permit amendment procedures under § 72.83 of this part;

(2) Changes in a substitution plan or reduced utilization plan that result in the addition of a new substitution unit or a new compensating unit under the plan;

(3) Addition of a nitrogen oxides averaging plan to a permit; and

(4) Changes in a Phase I extension plan, repowering plan, nitrogen oxides averaging plan, or nitrogen oxides compliance deadline extension.

(c)(1) Permit modifications shall follow the permit issuance requirements of:

(i) Subparts E, F, and G of this part, where the Administrator is the permitting authority; or

(ii) Subpart G of this part and § 70.7(e)(4)(ii) of this chapter, where the State is the permitting authority.

(2) For purposes of applying paragraph (c)(1) of this section, a permit modification shall be treated as an Acid Rain permit application, to the extent consistent with this subpart.

§ 72.82 Fast-track modifications.

The following procedures shall apply to all fast-track modifications.

(a) The designated representative shall serve a copy of the fast-track modification on the Administrator, the permitting authority, and any person entitled to a written notice under § 72.65(b)(1) (ii), (iii) and (iv) of this part. Within 5 business days of serving such copies, the designated representative shall also give public notice by publication in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

(b) The public shall have a period of 30 days, commencing on the date of publication of the notice, to comment on the fast-track modification. Comments shall be submitted in writing to the permitting authority and to the designated representative.

(c) The designated representative shall submit the fast-track modification to the permitting authority on or before commencement of the public comment period.

(d) Within 30 days of the close of the public comment period, the permitting authority shall consider the fast-track modification and the comments received and approve, in whole or in part or with changes or conditions as appropriate, or disapprove the modification. A fast-track modification shall be effective immediately upon issuance, in accordance with § 70.7(a)(1)(v) of this chapter as applied to significant permit modifications.

§ 72.83 Administrative permit amendment.

(a) Acid Rain permit revisions that shall follow the administrative permit amendment procedures are:

(1) Activation of a compliance option conditionally approved by the permitting authority; *provided* that all requirements for activation under subpart D of this part are met;

(2) Changes in the designated representative or alternative designated representative; *provided* that a new certificate of representation is submitted;

(3) Correction of typographical errors;

(4) Changes in names, addresses, or telephone or facsimile numbers;

(5) Changes in the owners or operators; *provided* that a new

certificate of representation is submitted within 30 days;

(6) Termination of a compliance option in the permit; *provided* that all requirements for termination under subpart D of this part shall be met and this procedure shall not be used to terminate a repowering plan after December 31, 1999 or a Phase I extension plan;

(7) Changes in a substitution or reduced utilization plan that do not result in the addition of a new substitution unit or a new compensating unit under the plan;

(8) Changes in the date, specified in a unit's Acid Rain permit, of commencement of operation of qualifying Phase I technology, *provided* that they are in accordance with § 72.42 of this part;

(9) Changes in the date, specified in a new unit's Acid Rain permit, of commencement of operation or the deadline for monitor certification, *provided* that they are in accordance with § 72.9 of this part;

(10) The addition of or change in a nitrogen oxides alternative emissions limitation demonstration period, *provided* that the requirements of regulations implementing section 407 of the Act are met; and

(11) Incorporation of changes that the Administrator has determined to be similar to those in paragraphs (a) (1) through (10) of this section.

(b) Administrative amendments shall follow the procedures set forth at § 70.7(d)(3) of this chapter. Where the State is the permitting authority, the permitting authority shall submit the revised portion of the permit to the Administrator within 10 working days after the date of final action on the request for an administrative amendment.

§ 72.84 Automatic permit amendment.

The following permit revisions shall be deemed to amend automatically, and become a part of the affected unit's Acid Rain permit by operation of law without any further review:

(a) Upon recordation by the Administrator under part 73 of this chapter, all allowance allocations to, transfers to, and deductions from an affected unit's Allowance Tracking System account; and

(b) Incorporation of an offset plan that has been approved by the Administrator under part 77 of this chapter.

§ 72.85 Permit reopenings.

(a) As provided in § 70.7(f) of this chapter, the permitting authority shall reopen an Acid Rain permit for cause, including whenever additional requirements become applicable to any affected unit governed by the permit.

(b) In reopening an Acid Rain permit for cause, the permitting authority shall issue a draft permit changing the provisions, or adding the requirements, for which the reopening was necessary. The draft permit shall be subject to the requirements of subparts E, F, and G of this part.

(c) As provided in §§ 72.73(b)(2) and 72.74(b)(2) of this part, the permitting authority shall reopen an Acid Rain permit to incorporate nitrogen oxides requirements, consistent with section 407 of the Act and regulations implementing section 407 of the Act.

(d) Any reopening of an Acid Rain permit shall not affect the term of the permit.

Subpart I—Compliance Certification

§ 72.90 Annual compliance certification report.

(a) *Applicability and Deadline.* For each calendar year in which a unit is subject to the Acid Rain emissions limitations, the designated representative of the source at which the unit is located shall submit to the Administrator, within 60 days after the end of the calendar year, an annual compliance certification report for the unit.

(b) *Contents of Report.* The designated representative shall include in the annual compliance certification report under paragraph (a) of this section the following elements, in a format prescribed by the Administrator, concerning the unit and the calendar year covered by the report:

(1) Identification of the unit;

(2) For all Phase I units, the information in accordance with §§ 72.91(a) and 72.92(a) of this part;

(3) If the unit is governed by an approved Phase I extension plan, then the information in accordance with § 72.93 of this part;

(4) At the designated representative's option, the total number of allowances to be deducted for the year, using the formula in § 72.95 of this part, and the serial numbers of the allowances that are to be deducted;

(5) At the designated representative's option, for units that share a common stack and whose emissions of sulfur dioxide are not monitored separately or apportioned in accordance with part 75 of this chapter, the percentage of the total number of allowances under paragraph (b)(4) of this section for all such units that is to be deducted from each unit's compliance subaccount; and

(6) The compliance certification under paragraph (c) of this section.

(c) *Annual Compliance Certification.* In the annual compliance certification report under paragraph (a) of this section, the designated representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the affected units at the source in compliance with the Acid Rain Program, whether each affected unit for which the compliance certification is submitted was operated during the calendar year covered by the report in compliance with the requirements of the Acid Rain Program applicable to the unit, including:

(1) Whether the unit was operated in compliance with the applicable Acid Rain emissions limitations, including whether the unit held allowances, as of the allowance transfer deadline, in its compliance subaccount (after accounting for any allowance deductions under § 73.34(c) of this chapter) not less than the unit's total sulfur dioxide emissions during the calendar year covered by the annual report;

(2) Whether the monitoring plan that governs the unit has been maintained to reflect the actual operation and monitoring of the unit and contains all information necessary to attribute monitored emissions to the unit;

(3) Whether all the emissions from the unit, or a group of units (including the unit) using a common stack, were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports;

(4) Whether the facts that form the basis for certification of each monitor at the unit or a group of units (including the unit) using a common stack or for using an Acid Rain Program excepted monitoring method or approved alternative monitoring method, if any, has changed; and

(5) If a change is required to be reported under paragraph (c)(4) of this section, specify the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.

§ 72.91 Phase I unit adjusted utilization.

(a) *Annual Compliance Certification Report.* The designated representative for each Phase I unit shall include in the annual compliance certification report the unit's adjusted utilization for the

calendar year covered by the report, calculated as follows:

Adjusted utilization-baseline–actual utilization–plan reductions+ compensating generation provided to other units

where:

(1) "Baseline" is as defined in § 72.2 of this part.

(2) "Actual utilization" is the actual annual heat input (in mmBtu) of the unit for the calendar year determined in accordance with part 75 of this chapter.

(3) "Plan reductions" are the reductions in actual utilization, for the calendar year, below the baseline that are accounted for by an approved reduced utilization plan. The designated representative for the unit shall calculate the "plan reductions" (in mmBtu) using the following formula and converting all values in Kwh to mmBtu using the actual annual average heat rate (Btu/Kwh) of the unit (determined in accordance with part 75 of this chapter) before the employment of any improved unit efficiency measures under an approved plan:

Plan reductions=reduction from energy conservation+reduction from improved unit efficiency improvements+shifts to designated sulfur-free generators+shifts to designated compensating units

where:

(i) "Reduction from energy conservation" is a good faith estimate of the expected kilowatt hour savings during the calendar year from all conservation measures under the reduced utilization plan and the corresponding reduction in heat input (in mmBtu) resulting from those savings. The verified amount of such reduction shall be submitted in accordance with paragraph (b) of this section.

(ii) "Reduction from improved unit efficiency" is a good faith estimate of the expected improvement in heat rate during the calendar year and the corresponding reduction in heat input (in mmBtu) at the Phase I unit as a result of all improved unit efficiency measures under the reduced utilization plan. The verified amount of such reduction shall be submitted in accordance with paragraph (b) of this section.

(iii) "Shifts to sulfur-free generators" is the reduction in utilization (in mmBtu), for the calendar year, that is accounted for by all sulfur-free generators designated under the reduced utilization plan and documented under paragraph (a)(6) of this section. This term equals the sum, for all such generators, of the "shift to sulfur-free generator" calculated for each generator using the following formula:

Shift to sulfur-free generator–actual sulfur-free utilization–[(average 1985–87 sulfur-free annual utilization) (1+percentage change in dispatch system sales)]

where:

(A) "Actual sulfur-free utilization" is the actual annual generation (in Kwh) of the designated sulfur-free generator for the calendar year converted to mmBtus.

(B) "Average 1985–87 sulfur-free utilization" is the sum of annual generation (in Kwh) for 1985, 1986, and 1987 for the designated sulfur-free generator, divided by three and converted to mmBtus.

(C) "Percentage change in dispatch system sales" is calculated as follows:

$$\text{Percentage change in dispatch system sales} = [S_c - (\sum_{y=1985}^{1987} S_y \div 3)] \div [\sum_{y=1985}^{1987} S_y \div 3]$$

where:

S=dispatch system sales (in Kwh)
c=calendar year
y=1985, 1986, or 1987

If the result of the formula for percentage change in dispatch system sales is less than or equal to zero, then percentage change in dispatch system sales shall be treated as zero only for purposes of paragraph (a)(3)(iii) of this section.

(D) If the result of the formula for "shift to sulfur-free generator" is less than or equal to zero, then "shift to sulfur-free generator" is zero.

(iv) "Shifts to designated compensating units" is the reduction in utilization (mmBtu) that is accounted for by increased generation at compensating units designated under the reduced utilization plan. This term equals the heat rate (Btu/Kwh) of the unit reducing utilization multiplied by the sum, for all such compensating units, of the "generation shifted to designated compensating unit" for each compensating unit. "Generation shifted to designated compensating unit" shall equal the amount of compensating generation (in Kwh) that the designated representatives of the unit reducing utilization and the compensating unit have certified (in their respective annual compliance certification reports) as the amount that will be converted to mmBtus and subtracted, in accordance with paragraph (a)(4) of this section, from the adjusted utilization for the compensating unit.

(4) "Designated compensating generation provided to other units" is the total amount of utilization necessary to provide the generation that was shifted to the unit as a designated compensating unit under any other reduced utilization plans. This term equals the heat rate of such unit multiplied by the sum of the portion of each "generation shifted to designated compensating units" that is attributed to the unit in the annual compliance certification reports submitted by the Phase I units under such other plans and that is certified under paragraph (a)(3)(iv) of this section. If the unit filing the report is not a designated compensating unit under any other plans, this term is zero.

(5) Notwithstanding paragraphs (a)(3)(i) and (iii) of this section, where two or more Phase I units include in "plan reductions", in their annual compliance certification reports for the calendar year, estimated kilowatt hour savings from the same specific conservation measures or increased utilization of the same sulfur-free generator:

(i) The designated representatives of all such units shall submit with their annual reports a certification signed by all such designated representatives. The certification shall apportion the total kilowatt hour savings or increased utilization among such units.

(ii) Each designated representative shall include in its annual report only its share of the total savings or total increased utilization, in accordance with the certification under paragraph (a)(5)(i) of this section.

(6) Where a unit includes in "plan reductions" under paragraph (a)(3) of this section the increase in utilization of a sulfur-free generator that is not in the unit's dispatch system, the designated representative of the unit shall submit, with its annual compliance certification report, documentation demonstrating that an amount of electrical energy at least equal to the portion of the "shift to sulfur-free generators" attributed to the sulfur-free generator in the annual report was actually purchased by the unit's dispatch system from the sulfur-free generator.

(b) *Confirmation Report.* (1) If a unit's annual compliance certification report

estimates any expected kilowatt hour savings or improvement in heat rate from energy conservation or improved unit efficiency measures under a reduced utilization plan, the designated representative shall submit, by July 1 of the year in which the annual report was submitted, a confirmation report. The Administrator may grant, for good cause shown, an extension of the time to file the confirmation report. The confirmation report shall include the following elements in a format prescribed by the Administrator:

(i) The verified kilowatt hour savings from each such energy conservation measure and the verified corresponding reduction in the unit's heat input resulting from each measure during the calendar year covered by the annual report. For purposes of this paragraph (b), all values in Kwh shall be converted to mmBtu using the actual annual heat rate (Btu/Kwh) of the unit (determined in accordance with part 75 of this chapter) before the employment of any improved unit measures under an approved reduced utilization plan.

(ii) The verified reduction in the heat rate achieved by each improved unit efficiency measure and the verified corresponding reduction in the unit's heat input resulting from such measure.

(iii) For all figures under paragraphs (b)(1) (i) and (ii) of this section:

(A) Documentation (which may follow the EPA Conservation Verification Protocol) verifying specified figures to the satisfaction of the Administrator; or

(B) Certification, by a State utility regulatory authority that has ratemaking jurisdiction over the utility system that paid for the measures in accordance with § 72.43(b)(2) of this part and over rates reflecting any of the amount paid for such measures and that meets the criteria in § 73.82(c)(1) (i) and (ii) of this chapter, that such authority verified specified figures related to demand-side measures; and

(C) Certification, by a utility regulatory authority that has ratemaking jurisdiction over the utility system that paid for the measures in accordance with § 72.43(b)(2) of this part and over rates reflecting any of the amount paid for such measures, that such authority verified specified figures related to supply-side measures.

(2) Notwithstanding paragraph (b)(1)(i) of this section, where two or more Phase I units include in the confirmation report the verified kilowatt hour savings from the same specific conservation measures:

(i) The designated representatives of all such units shall submit with their confirmation reports a certification signed by all such designated representatives. The certification shall apportion the total kilowatt hour savings among such units.

(ii) Each designated representative shall include in its confirmation report only its share of the total savings in accordance with the certification under paragraph (b)(2)(i) of this section.

(3) If the total, included in the confirmation report, of the amounts of verified reduction in the unit's heat input from energy conservation and unit efficiency measures equals the total estimated in the unit's annual compliance certification report from such measures for the calendar year, then the designated representatives shall include in the confirmation report a statement indicating that is true.

(4) If the total, included in the confirmation report, of the amounts of verified reduction in the units's heat input from energy conservation and improved unit efficiency measures is greater than the total estimated in the unit's annual compliance certification report from such measures for the calendar year, then the designated representative shall include in the confirmation report the number of allowances to be credited to the unit's compliance subaccount calculated using the following formula:

Allowances credited=(verified heat input reduction-estimated hear input reduction) × emissions rate ÷ 2000 lbs/ton

where:

(i) "Verified heat input reduction" is the total of the amounts of verified reduction in the units' heat input (in mmBtu) from energy conservation and improved unit efficiency measures included in the confirmation report.

(ii) "Estimated heat input reduction" is the total of the amounts of reduction in the unit's heat input (in mmBtu) accounted for by energy conservation and improved efficiency measures as estimated in the unit's annual compliance certification report for the calendar year.

(iii) "Emissions rate" is the "emissions rate" under § 72.92(c)(2)(v) of this part.

(5) If the total, included in the confirmation report, of the amounts of verified reduction in the unit's heat input from energy conservation and improved unit efficiency measures is less than the total estimated in the unit's annual compliance certification report for such measures for the calendar year, then the designated representative shall include in the confirmation report the number of allowances to be deducted from the unit's compliance subaccount, which equals the absolute value of the result of the formula for allowances credited under paragraph (b)(4) of this section.

(6) Unless paragraph (b)(3) of this section applies, the designated representative shall include in the confirmation report the adjusted amount of allowances that would have held in the unit's compliance subaccount if the deductions made under § 73.35(b) of this chapter had been based on the verified, rather than the estimated, reduction in the unit's heat input from energy conservation and improved efficiency measures, calculated as follows:

Adjusted amount of allowances=allowances held after deduction–excess emissions + allowances credited–allowances deducted

where:

(i) "*Allowances held after deductions*" is the amount of allowances held in the unit's compliance subaccount after deductions were made under § 73.35(b) of this chapter based on the annual compliance certification report.

(ii) "*Excess emission*" is the amount (if any) of excess emissions determined under § 73.35(b) for the calendar year based on the annual compliance certification report.

(iii) "*Allowances credited*" is the amount of allowances calculated under paragraph (b)(4) of this section.

(iv) "*Allowances deducted*" is the amount of allowances calculated under paragraph (b)(5) of this section.

(v) If the result of the formula for "adjusted amount of allowances" is negative, the absolute value of the result constitutes excess emissions of sulfur dioxide. If the result is positive, there are no excess emissions of sulfur dioxide.

(7) If the amount of excess emissions of sulfur dioxide calculated under paragraph (b)(6) of this section differs from the amount of excess emissions of sulfur dioxide determined under § 73.35(b) of this chapter based on the annual compliance certification report, then the designated representative shall include in the confirmation report a demonstration of: the number of allowances that should be deducted to offset any increase in excess emissions or returned to account for any decrease in excess emissions; and the amount of the excess emissions penalty (excluding interest) that should be paid or returned to account for the change in excess emissions. The Administrator will deduct immediately from the unit's compliance subaccount the amount of allowances that he or she determines is

necessary to offset any increase in excess emissions or will return immediately to the unit's compliance subaccount the amount of allowances that he or she determines is necessary to account for any decrease in excess emissions. The designated representative may identify the serial numbers of the allowances to be deducted or returned. In the absence of such identification, the deduction will be on a first-in, first-out basis under § 73.35(c)(2) of this chapter and the return will be at the Administrator's discretion.

(8) If the designated representative of a unit fails to submit on a timely basis a confirmation report (in accordance with paragraph (b) of this section) with regard to the estimate of expected kilowatt hour savings or improvement in heat rate from any energy conservation or improved unit efficiency measure under the reduced utilization plan, then the Administrator will reject such estimate and correct it to equal zero in the unit's annual compliance certification report that includes that estimate. The Administrator will deduct immediately, on a first-in, first-out basis under § 73.35(c)(2) of this chapter, the amount of allowances that he or she determines is necessary to offset any increase in excess emissions of sulfur dioxide that results from the correction and require the owners and operators to pay an excess emission penalty in accordance with part 77 of this chapter.

§ 72.92 Phase I unit allowance surrender.

(a) *Annual Compliance Certification Report.* If a Phase I unit's adjusted utilization for the calendar year under § 72.91(a) is greater than zero, then the designated representative shall include in the annual compliance certification report the following elements:

(1) The number of allowances that shall be surrendered for adjusted utilization using the formula in paragraph (c) of this section and the calculations that were performed to obtain that number.

(2) Identification of the amounts of adjusted utilization that were caused by a dispatch-system-wide decline in sales, a forced outage at the unit, or economic dispatching in accordance with § 72.43(e)(1).

(3) If the unit experienced a forced outage during the year that is used to account for any adjusted utilization of the unit under paragraph (a)(2) of this section or if the unit is currently experiencing a forced outage that is expected to last longer than 4 months:

(i) A statement specifying the event that caused the forced outage;

(ii) The amount of adjusted utilization attributable to the forced outage (in mmBtu and Kwh), if any;

(iii) The duration or expected duration of the forced outage;

(iv) If the unit has not been returned to normal service, the expected date on which the unit will be returned to normal service; and

(v) A demonstration of the measures taken by the owners and operators to restore the unit to normal service as expeditiously as practicable, including any measures taken to prevent any similar forced outage in the future.

(b) *Other Submissions.*

(1) If a Phase I unit experienced a force outage during the calendar year that will cause the unit to shut down permanently and shift generation to any unit that would not otherwise be affected during Phase I, the designated representative shall submit to the Administrator within 60 days of the determination to shut down the unit permanently:

(i) A reduced utilization plan that designates one or more compensating units to which the unit will shift generation; or

(ii) A certification, from an independent auditor or a utility regulatory authority with ratemaking jurisdiction over any owner of the unit and over rates reflecting any capital or operating costs of the unit, that it is not possible to restore the unit to service at a reasonable cost.

(2)(i) If any Phase I unit in a dispatch system is governed during the calendar year by an approved reduced utilization plan relying on sulfur-free generation, then the designated representatives of all affected units in such dispatch system shall jointly submit, within 60 days of the end of the calendar year, a dispatch system data report that includes the following elements in a format prescribed by the Administrator:

(A) The name of the dispatch system as reported under § 72.33;

(B) The calculation of "percentage change in dispatch system sales" under § 72.91(a)(3)(iii)(C);

(C) A certification that each designated representative will use this figure, as appropriate, in its annual compliance certification report and will submit upon request the data supporting the calculation; and

(D) The signatures of all the designated representatives.

(ii) If any Phase I unit in a dispatch system has adjusted utilization greater than zero for the calendar year, then the designated representatives of all Phase I units in such dispatch system shall jointly submit, within 60 days of the end of the calendar year, a dispatch system data report that includes the following elements in a format prescribed by the Administrator:

(A) The name of the dispatch system as reported under § 72.33;

(B) The calculation of "percentage change in dispatch system sales" under § 72.91(a)(3)(iii)(C);

(C) The calculation of "dispatch system adjusted utilization" under paragraph (c)(2)(i) of this section;

(D) The calculation of "dispatch system aggregate baseline" under paragraph (c)(2)(ii) of this section;

(E) The calculation of "fraction of generation within dispatch system" under paragraph (c)(2)(v)(A) of this section;

(F) The calculation of "dispatch system emissions rate" under paragraph (c)(2)(v)(C) of this section;

(G) A certification that each designated representative will use these figures, as appropriate, in its annual compliance certification report and will submit upon request the data supporting these calculations; and

(H) The signatures of all the designated representatives.

(c) *Allowance Surrender Formula.* (1) As provided under the allowance surrender formula in paragraph (c)(2) of this section:

(i) Allowances are not surrendered for deduction for the portion of adjusted utilization accounted for by:

(A) Shifts in generation from the unit to other Phase I units;

(B) A dispatch-system-wide sales decline;

(C) Plan reductions under a reduced utilization plan as calculated under § 72.91; and

(D) Foreign generation.

(ii) Allowances are surrendered for deduction for the portion of adjusted utilization that is not accounted for under paragraph (c)(1)(i) of this section.

(2) The designated representative shall surrender for deduction the number of allowances calculated using the following formula:

$$\text{Allowances surrendered} = [\text{dispatch system adjusted utilization} + (\text{dispatch system aggregate baseline} \times \text{percentage change in dispatch system sales})] \times \text{unit's share} \times \text{emissions rate} \div 2000 \text{ lbs/ton}.$$

If the result of the formula for "allowances surrendered" is less than or equal to zero, then no allowances are surrendered.

(i) *Calculating Dispatch System Adjusted Utilization.* "Dispatch system adjusted utilization" (in mmBtu) is the sum of the adjusted utilization under § 72.91(a) for all Phase I units in the dispatch system. If "dispatch system adjusted utilization" is less than or

equal to zero, then no allowances are surrendered by any unit in that dispatch system.

(ii) *Calculating Dispatch System Aggregate Baseline.* "Dispatch system aggregate baseline" is the sum of the baselines (as defined in § 72.2 of this chapter) for all Phase I units in the dispatch system.

(iii) *Calculating Percentage Change in Dispatch System Sales.* "Percentage change in dispatch system sales" is the "percentage change in dispatch system sales" under § 72.91 (a)(3)(iii)(C); *provided* that if result of the formula in § 72.91(a)(3)(iii)(C) is greater than or equal to zero, the value shall be treated as zero only for purposes of paragraph (c)(2) of this section.

(iv) *Calculating Unit's Share.* "Unit's share" is the unit's adjusted utilization divided by the sum of the adjusted utilization for all Phase I units within the dispatch system that have adjusted utilization of greater than zero and is calculated as follows:

$$Unit's\ share = \frac{U_{unit}}{\sum_{i=1}^{m} U_i}$$

where:

(A) U_{unit} = the unit's adjusted utilization for the calendar year;

(B) U_i = the adjusted utilization of a Phase I unit in the dispatch system for the calendar year; and

(C) m = all Phase I units in the dispatch system having an adjusted utilization greater than 0 for the calendar year.

(v) *Calculating Emissions Rate.* "Emissions rate" (in lbs./mmBtu) is the weighted average emissions rate for sulfur dioxide of all units, within and outside the dispatch system, that contributed to the dispatch system's electrical output for the year, calculated as follows:

Emissions rate = [fraction of generation within dispatch system × dispatch system emissions rate] + [fraction of generation outside dispatch system × fraction of non-Phase I and non-foreign generation in NERC region × NERC region average emissions rate]

where:

(A) "Fraction of generation within dispatch system" is the fraction of the dispatch system's total sales accounted for by generation from units within the dispatch system. This term equals the total generation (in Kwh) by all units and generators within the dispatch system for the calendar year divided by the total sales (in Kwh) by the dispatch system for the calendar year.

(B) "Fraction of generation outside dispatch system" = 1 – fraction of generation within dispatch system.

(C) "Dispatch system emissions rate" is the weighted average rate (in lbs/mmBtu) for the dispatch system calculated as follows:

$$\text{Dispatch system emissions rate} = \sum_{i=1}^{k} g_i r_i \div \sum_{i=1}^{k} g_i$$

where:

g_i = a Phase II unit's utilization for the calendar year

r_i = a Phase II unit's emission rate, determined in accordance with part 75 of this chapter, for the calendar year

k = number of Phase II units in the dispatch system

(D) "Fraction of non-Phase I and non-foreign generation in NERC region" is the portion of the NERC region's total sales generated by units other than Phase I units or foreign sources in the unit's NERC region in 1985, as set forth in Table 1 of this section.

(E) "NERC region average emissions rate" is the weighted average emissions rate (in lbs/mmBtu) for the unit's NERC region in 1985, as set forth in Table 1 of this section.

TABLE 1.—NERC REGION GENERATION AND EMISSIONS RATE IN 1985

NERC region	Fraction of non-phase I and non-foreign generation in NERC region	NERC weighted average emissions rate (lb/mmBtu)
WSCC	1.000	0.466
SPP	0.940	0.847
SERC	0.662	1.315
NPCC	0.664	1.058
MAPP	0.946	1.171
MAIN	0.577	1.495
MAAC	0.683	1.599
ERCOT	1.000	0.491
ECAR	0.541	1.564

§ 72.93 Units with Phase I extension plans.

Annual Compliance Certification Report. The designated representative for a control unit governed by a Phase I extension plan shall include in the unit's annual compliance certification report for calendar year 1997, the start-up test results upon which the vendor is released from liability under the vendor certification of guaranteed sulfur dioxide removal efficiency under § 72.42(c)(12).

§ 72.94 Units with repowering extension plans.

(a) *Design and Engineering and Contract Requirements.* No later than January 1, 2000, the designated representative of a unit governed by an approved repowering plan shall submit to the Administrator and the permitting authority:

(1) Satisfactory documentation of a preliminary design and engineering effort.

(2) A binding letter agreement for the executed and binding contract (or for each in a series of executed and binding contracts) for the majority of the equipment to repower the unit using the technology conditionally approved by the Administrator under § 72.44(d)(3).

(3) The letter agreement under paragraph (a)(2) of this section shall be signed and dated by each party and specify:

(i) The parties to the contract;

(ii) The date each party executed the contract;

(iii) The unit to which the contract applies;

(iv) A brief list identifying each provision of the contract;

(v) Any dates to which the parties agree, including construction completion date;

(vi) The total dollar amount of the contract; and

(vii) A statement that a copy of the contract is on site at the source and will be submitted upon written request of the Administrator or the permitting authority.

(b) *Removal From Operation to Repower.* The designated representative of a unit governed by an approved repowering plan shall notify the Administrator in writing at least 60 days in advance of the date on which the existing unit is to be removed from operation so that the qualified repowering technology can be installed, or is to be replaced by another unit with the qualified repowering technology, in accordance with the plan.

(c) *Commencement of Operation.* Not later than 60 days after the units repowered under an approved repowering plan commences operation at full load, the designated representative of the unit shall submit a report comparing the actual hourly emissions and percent removal of each pollutant controlled at the unit to the actual hourly emissions and percent removal at the existing unit under the plan prior to repowering, determined in accordance with part 75 of this chapter.

(d) *Decision to Terminate.* If at any time before the end of the repowering extension the owners and operators decide to terminate good faith efforts to design, construct, and test the qualified repowering technology on the unit to be repowered under an approved repowering plan, then the designated

representative shall submit a notice to the Administrator by the earlier of the end of the repowering extension or a date within 30 days of such decision, stating the date on which the decision was made.

§ 72.95 Allowance deduction formula.

The following formula shall be used to determine the total number of allowances to be deducted for the calendar year from the allowances held in an affected unit's compliance subaccount as of the allowance transfer deadline applicable to that year:

Total allowances deducted=Tons emitted + Allowances surrendered for underutilization+Allowances deducted for Phase I extensions

where:

(a) "Tons emitted" is the total tons of sulfur dioxide emitted by the unit during the calendar year, as reported in accordance with part 75 of this chapter.

(b) "Allowances surrendered for underutilization" is the total number of allowances calculated in accordance with § 72.92 (a) and (c).

(c) "Allowances deducted for Phase I extensions" is the total number of allowances calculated in accordance with § 72.42(f)(1)(i).

§ 72.96 Administrator's action on compliance certifications.

(a) The Administrator may review, and conduct independent audits concerning, any compliance certification and any other submission under the Acid Rain Program and make appropriate adjustments of the information in the compliance certifications and other submissions.

(b) The Administrator may deduct allowances from or return allowances to a unit's Allowance Tracking System account in accordance with part 73 of this chapter based on the information in the compliance certifications and other submissions, as adjusted.

Appendix A to Part 72—Methodology for Annualization of Emissions Limits

For the purposes of the Acid Rain Program, 1985 emissions limits must be expressed in pounds of SO_2 per million British Thermal Unit of heat input (lb/mmBtu) and expressed on an annual basis.

Annualization factors are used to develop annual equivalent SO_2 limits as required by § 402(18) of the CAA. Many emission limits are enforced on a shorter term basis (or averaging period) than annually. Because of the variability of sulfur in coal and, in some cases, scrubber performance, meeting a particular limit with an averaging period of less than a year and at a specified statutory emissions level would require a lower annual average SO_2 emission rate (or annual equivalent SO_2 limit) than would the shorter term statutory limit. EPA has selected a compliance level of one exceedance per 10 years. For example, an SO_2 emission limit of 1.2 lbs/MMBtu, enforced for a scrubbed unit over a 7-day averaging period, would result in an annualized SO_2 emission limit of 1.16 lbs/MMBtu. In general, the shorter the averaging period, the lower the annual equivalent would be. Thus, the annualization of limits is established by multiplying each federally enforceable limit by an annualization factor that is determined by the averaging period and whether or not it's a scrubbed unit.

TABLE A–1.—SO_2 EMISSION AVERAGING PERIODS AND ANNUALIZATION FACTORS

Definition	Annualization factor	
	Scrubbed unscrubbed	
	Unit	Unit
Oil/gas unit	1.00	1.00
<=1 day	0.93	0.89
1 week	0.97	0.92
30 days	1.00	0.96
90 days	1.00	1.00
1 year	1.00	1.00
Not specified	0.93	0.89
At all times	0.93	0.89
Coal unit: No Federal limit or limit unknown	1.00	1.00

Appendix B to Part 72—Methodology for Conversion of Emissions Limits

For the purposes of the Acid Rain Program, all emissions limits must be expressed in pounds of SO_2 per million British Thermal Unit of heat input (lb/mmBtu).

The factor for converting pounds of sulfur to pounds of SO_2 is based on the molecular weights of sulfur (32) and SO_2 (64). Limits expressed as percentage of sulfur or parts per million (ppm) depend on the energy content of the fuel and thus may vary, depending on several factors such as fuel heat content and atmospheric conditions. Generic conversions for these limits are based on the assumed average energy contents listed in Table A–2. In addition, limits in ppm vary with boiler operation (e.g., load and excess air); generic conversions for these limits assume, conservatively, very low excess air. The remaining factors are based on site-specific heat rates and capacities to develop conversions for Btu per hour. Standard conversion factors for residual oil are 42 gal/bbl and 7.88 lbs/gal.

TABLE B–1.—CONVERSION FACTORS

[Emission limits converted to lbs SO_2/MMBtu by multiplying as below]

Unit measurement	Plant fuel type			
	Bituminous coal	Subbituminous coal	Lignite coal	Oil
Lbs sulfur/MMBtu	2.0	2.0	2.0	2.0
% sulfur in fuel	1.66	2.22	2.86	1.07
Ppm SO_2	0.00287	0.00384	.....	0.00167
Ppm sulfur in fuel	.....	.....	.....	0.00334
Tons SO_2/hour	2,000,000/(HEATRATE*SUMNDCAP*capacity factor) [1]			
Lbs SO_2/hour	1,000/(HEATRATE*SUMNDCAP*capacity factor) [1]			

[1] In these cases, if the limit was specified as the "site" limit, the summer net dependable capability for the entire plant is used; otherwise, the summer net dependable capability for the unit is used. For units listed in the NADB, "HEATRATE" shall be that listed in the NADB under that field and "SUMNDCAP" shall be that listed in the NADB under that field. For units not listed in the NADB, "HEATRATE" is the generator net full load heat rate reported on Form EIA–860 and "SUMNDCAP" is the summer net dependable capability of the generator (in MWe) as reported on Form EIA–860.

TABLE B–2.—ASSUMED AVERAGE ENERGY CONTENTS

Fuel type	Average heat content
Bituminous Coal	24 MMBtu/ton.
Subbituminous Coal	18 MMBtu/ton.
Lignite Coal	14 MMBtu/ton.
Residual Oil	5.2 MMBtu/bbl.

Appendix C to Part 72—Actual 1985 Yearly SO_2 Emissions Calculation

The equation used to calculate the yearly SO_2 emissions (SO2) is as follows:

SO2 = (coal SO_2 emissions) + (oil SO_2 emissions) (in tons)

If gas is the only fuel, gas emissions are defaulted to 0.

Each fuel type SO_2 emissions is calculated on a yearly basis, using the equation:

fuel SO_2 emissions (in tons) = (yrly wtd. av. fuel sulfur %) × (AP–42 fact.) × (1–scrb. effic. %/100) × (units conver. fact.) × (yearly fuel burned)

For coal, the yearly fuel burned is in tons/yr and the AP–42 factor (which accounts for the ash retention of sulfur in coal), in lbs SO_2 ton coal, is by coal type:

Coal type	AP–42 factor
Bituminous, anthracite	39 lbs/ton
Subbituminous	35
Lignite	30

For oil, the yearly fuel burned is in gal/yr. If it is in bbl/yr, convert using 42 gal/bbl oil. The AP–42 factor (which accounts for the oil density), in lbs SO_2/thousand gal oil, is by oil type:

Oil type	AP–42 factor
Distillate (light)	142 lbs/1,000 gal
Residual (heavy)	157

For all fuel, the units conversion factor is 1 ton/2000 lbs.

2. The authority citation for part 73 continues to read as follows:

Authority: 42 U.S.C. 7651.

3. Part 73 is amended by revising subpart A and by adding subparts B through D to read as follows:

PART 73—ALLOWANCE SYSTEM

Subpart A—Background and Summary

Sec.
73.1 Purpose and scope.
73.2 Applicability.
73.3 General.

Subpart B—Allowance Allocations

73.10 Initial allocations for Phase I.
73.25 Phase I extension reserve.
73.27 Special allowance reserve.

Subpart C—Allowance Tracking System

73.30 Allowance tracking system accounts.
73.31 Establishment of accounts.
73.32 Allowance account contents.
73.33 Authorized account representative.
73.34 Recordation in accounts.
73.35 Compliance.
73.36 Banking.
73.37 Account error and dispute resolution.
73.38 Closing of accounts.

Subpart D—Allowance Transfers

73.50 Scope and submission of transfers.
73.51 Prohibition.
73.52 EPA recordation.
73.53 Notification.

Subpart A—Background and Summary

§ 73.1 Purpose and scope.

The purpose of this Part is to establish the requirements and procedures for the following:

(a) The allocation of sulfur dioxide emissions allowances;

(b) The tracking, holding, and transfer of allowances;

(c) The deduction of allowances for purposes of compliance and for purposes of offsetting excess emissions pursuant to parts 72 and 77 of this chapter;

(d) The sale of allowances through EPA-sponsored auctions and a direct sale, including the independent power producers written guarantee program; and

(e) The application for, and distribution of, allowances from the Conservation and Renewable Energy Reserve.

§ 73.2 Applicability.

The following parties shall be subject to the provisions of this Part:

(a) Owners, operators, and designated representatives of affected sources and affected units pursuant to § 72.6 of this chapter;

(b) Any new independent power producer as defined in section 416 of the Act and § 72.2 of this chapter, except as provided in section 405(g)(6) of the Act;

(c) Any owner of an affected unit who may apply to receive allowances under the Energy Conservation and Renewable Energy Reserve Program established in accordance with section 404(f) of the Act;

(d) Any small diesel refinery as defined in § 72.2 of this chapter, and

(e) Any other person, as defined in § 72.2 of this chapter, who chooses to purchase, hold, or transfer allowances as provided in section 403(b) of the Act.

§ 73.3 General.

Part 72 of this chapter, including §§ 72.2 (definitions), 72.3 (measurements, abbreviations, and acronyms), 72.4 (Federal authority), 72.5 (State authority), 72.6 (applicability), 72.7 (new units exemption), 72.8 (retired unit exemption), 72.9 (standard requirements), 72.10 (availability of information), and 72.11 (computation of time) of part 72, subpart A of this chapter, shall apply to this part. The procedures for appeals of decisions of the Administrator under this part are contained in part 78 of this chapter. Sections 73.3 (Definitions) and 73.4 (Deadlines), which were previously published with subpart E of this part—"Auctions, Direct Sales, and Independent Power Producers Written Guarantee", are codified at §§ 72.2 and 72.12 of this chapter, respectively.

Subpart B—Allowance Allocations

§ 73.10 Initial allocations for Phase I.

(a) *Phase I Allowances.* The Administrator will allocate allowances to the unit account for each unit listed in Table 1 of this section in the amount listed in Column A to be held in each future year subaccount for the years 1995 through 1999.

TABLE 1.—PROPOSED PHASE I ALLOWANCE ALLOCATIONS

State name	Plant name	Boiler	Column A final phase 1 allocation	Column B auction and sales reserve
Alabama	Colbert	1	13213	357
		2	14907	403
		3	14995	405
		4	15005	405
		5	36202	978
	E.C. Gaston	1	17624	476
		2	18052	488
		3	17828	482

TABLE 1.—PROPOSED PHASE I ALLOWANCE ALLOCATIONS—Continued

State name	Plant name	Boiler	Column A final phase 1 allocation	Column B auction and sales reserve
		4	18773	507
		5	58265	1575
Florida	Big Bend	BB01	27662	748
		BB02	26387	713
		BB03	26036	704
	Crist	6	18695	505
		7	30846	834
Georgia	Bowen	1BLR	54838	1482
		2BLR	53329	1441
		3BLR	69862	1888
		4BLR	69852	1888
	Hammond	1	8549	231
		2	8977	243
		3	8676	234
		4	36650	990
	Jack McDonough	MB1	19386	524
		MB2	20058	542
	Wansley	1	68908	1862
		2	63708	1722
	Yates	Y1BR	7020	190
		Y2BR	6855	185
		Y3BR	6767	183
		Y4BR	8676	234
		Y5BR	9162	248
		Y6BR	24106	652
		Y7BR	20915	565
Illinois	Baldwin	1	46052	1245
		2	48685	1316
		3	46644	1261
	Coffeen	01	12925	349
		02	39102	1057
	Grand Tower	09	6479	175
	Hennepin	2	20182	545
	Joppa Steam	1	12259	331
		2	10487	283
		3	11947	323
		4	11061	299
		5	11119	301
		6	10341	279
	Kincaid	1	34585	934
		2	37063	1002
	Meredosia	05	15227	411
	Vermilion	2	9735	263
Indiana	Bailly	7	12256	331
		8	17134	463
	Breed	1	20280	548
	Cayuga	1	36581	989
		2	37415	1011
	Cliffy Creek	1	19620	530
		2	19289	521
		3	19873	537
		4	19552	528
		5	18851	509
		6	19844	536
	Elmer W. Stout	50	4253	115
		60	5229	141
		70	25883	699
	F.B. Culley	2	4703	127
		3	18603	503
	Frank E. Ratts	1SG1	9131	247
		2SG1	9296	251
	Gibson	1	44288	1197
		2	44955	1215
		3	45033	1217
		4	44200	1195
	H.T. Pritchard	6	6325	171
	Michigan City	12	25553	691
	Petersburg	1	18011	487
		2	35496	959
	R. Gallagher	1	7115	192
		2	7950	216
		3	7159	193
		4	8386	227
	Tanners Creek	U4	27209	735
	Wabash River	1	4385	118
		2	3135	85
		3	4111	111
		5	4023	109
		6	13462	364

TABLE 1.—PROPOSED PHASE I ALLOWANCE ALLOCATIONS—Continued

State name	Plant name	Boiler	Column A final phase 1 allocation	Column B auction and sales reserve
	Warrick	4	29577	799
Iowa	Burlington	1	10428	282
	Des Moines	11	2259	61
	George Neal	1	2571	69
	Milton L. Kapp	2	13437	363
	Prairie Creek	4	7965	215
	Riverside	9	3885	105
Kansas	Quindaro	2	4109	111
Kentucky	Coleman	C1	10954	296
		C2	12502	338
		C3	12015	325
	Cooper	1	7254	196
		2	14917	403
	E.W. Brown	1	6923	187
		2	10623	287
		3	25413	687
	Elmer Smith	1	6348	172
		2	14031	379
	Ghent	1	27662	748
	Green River	5	7614	206
	H.L. Spurlock	1	22181	599
	HMP&L Station 2	H1	12989	351
		H2	11996	324
	Paradise	3	57613	1557
	Shawnee	10	9902	268
Maryland	C.P. Crane	1	10058	272
		2	8987	243
	Chalk Point	1	21333	577
		2	23690	640
	Morgantown	1	34332	928
		2	37467	1013
Michigan	J.H. Campbell	1	18773	507
		2	22453	607
Minnesota	High Bridge	6	4156	112
Mississippi	Jack Watson	4	17430	471
		5	35734	966
Missouri	Asbury	1	15764	426
	James River	5	4722	128
	LaBadie	1	39055	1055
		2	36718	992
		3	39249	1061
		4	34994	946
	Montrose	1	7196	194
		2	7964	216
		3	9824	266
	New Madrid	1	27497	743
		2	31625	855
	Sibley	3	15170	410
	Sioux	1	21076	504
		2	23067	623
	Thomas Hill	MB1	9980	270
		MB2	18880	510
New Hampshire	Merrimack	1	9922	268
		2	21421	579
New Jersey	B.L. England	1	8822	238
		2	11412	308
New York	Dunkirk	3	12268	332
		4	13690	370
	Greenidge	6	7342	198
	Milliken	1	10876	294
		2	12083	327
	Northport	1	19289	521
		2	23476	634
		3	25783	697
	Port Jefferson	3	10194	276
		4	12006	324
Ohio	Ashtabula	7	18351	496
	Avon Lake	11	12771	345
		12	33413	903
	Cardinal	1	37568	1015
		2	42008	1135
	Conesville	1	4615	125
		2	5360	145
		3	6029	163
		4	53463	1445
	Eastlake	1	8551	231
		2	9471	256
		3	10984	297
		4	15908	430

TABLE 1.—PROPOSED PHASE I ALLOWANCE ALLOCATIONS—Continued

State name	Plant name	Boiler	Column A final phase 1 allocation	Column B auction and sales reserve
		5	37349	1009
	Edgewater	13	5536	150
	Gen. J.M. Gavin	1	86690	2343
		2	88312	2387
	Kyger Creek	1	18773	507
		2	18072	488
		3	17438	471
		4	18218	492
		5	18247	493
	Miami Fort	5–1	417	11
		5–2	417	11
		6	12475	337
		7	42216	1141
	Muskingum River	1	16312	441
		2	15533	420
		3	15293	413
		4	12914	349
		5	44364	1199
	Niles	1	7608	206
		2	9975	270
	Picway	9	5404	146
	R.E. Burger	5	3371	91
		6	3371	91
		7	11818	319
		8	13626	368
	W.H. Sammis	5	26496	716
		6	43773	1183
		7	47380	1280
	Walter C. Beckjord	5	9811	265
		6	25235	682
Pennsylvania	Armstrong	1	14031	379
		2	15024	406
	Brunner Island	1	27030	730
		2	30282	818
		3	52404	1416
	Cheswick	1	38139	1031
	Conemaugh	1	58217	1573
		2	64701	1749
	Hatfield's Ferry	1	36835	995
		2	36338	982
		3	39210	1060
	Martins Creek	1	12327	333
		2	12483	337
	Portland	1	5784	156
		2	9961	269
	Shawville	1	10048	272
		2	10046	272
		3	13646	374
		4	13700	370
	Sunbury	3	8530	230
		4	11149	301
Tennessee	Allen	1	14917	403
		2	16329	441
		3	15258	412
	Cumberland	1	84419	2281
		2	92344	2496
	Gallatin	1	17400	470
		2	16855	455
		3	19493	527
		4	20701	559
	Johnsonville	1	7585	205
		10	7351	199
		2	7828	212
		3	8189	221
		4	7780	210
		5	8023	217
		6	7682	208
		7	8744	236
		8	8471	229
		9	6894	186
West Virginia	Albright	3	11684	316
	Fort Martin	1	40496	1094
		2	40116	1084
	Harrison	1	47341	1279
		2	44936	1214
		3	40408	1092
	Kammer	1	18247	493
		2	18948	512
		3	16932	458

TABLE 1.—PROPOSED PHASE I ALLOWANCE ALLOCATIONS—Continued

State name	Plant name	Boiler	Column A final phase 1 allocation	Column B auction and sales reserve
	Mitchell	1	42823	1157
		2	44312	1198
	M.T. Storm	1	42570	1150
		2	34644	936
		3	41314	1116
Wisconsin	Edgewater	4	24099	651
	Genoa	1	22103	597
	Nelson Dewey	1	5852	158
		2	6504	176
	North Oak Creek	1	5083	137
		2	5005	135
		3	5229	141
		4	6154	166
	Pulliam	8	7312	198
	South Oak Creek	5	9416	254
		6	11723	317
		7	15754	426
		8	15375	415

(b) [Reserved]

§ 73.25 Phase I extension reserve.

The Administrator will initially allocate 3.5 million allowances to the Phase I Extension Reserve account of the Allowance Tracking System. Allowances from this Reserve will be allocated to units under § 72.42 of this chapter. Allowances remaining in the Phase I Extension Reserve account following allocation of all extension allowances under § 72.42 of this chapter will remain in the Reserve.

§ 73.27 Special allowance reserve.

(a) *Establishment of Reserve.* (1) The Administrator will allocate 150,000 allowances annually for calendar years 1995 through 1999 to the Auction Subaccount of the Special Allowance Reserve.

(b) *Distribution of Proceeds.* Monetary proceeds from the auctions and sales of allowances from the Special Allowance Reserve (under subpart E of this part) for use in calendar years 1995 through 1999 will be distributed to the designated representative of the unit according to the following equation:

unit proceeds=(Column B of Table 1 of section 73.10/150,000) × total proceeds

(c) *Reallocation of Allowances.* Allowances remaining in the Special Allowance Reserve following the annual auctions and sales (under subpart E of this part) for use in calendar years 1995 through 1999 will be reallocated to the unit's Allowance Tracking System Account according to the following equation:

unit allowances = (Column B of Table 1 of section 73.10/150,000) × Allowances remaining

(d) *Calculation Rounding.* All proceeds under this section shall be distributed as whole dollars. All calculations for such allowances shall be rounded down for decimals less than .5 and up for decimals of .5 or greater.

(e) *Achieving Exact Totals.* (1) If the sum of the proceeds to be distributed under paragraph (b) of this section exceeds the total proceeds or the allowances to be reallocated under paragraph (c) of this section exceeds the allowances remaining, then the Administrator will withdraw one dollar or allowance from each unit, beginning with the unit receiving the largest number of dollars or allowances, in descending order, until the distribution balances with the proceeds and the reallocated allowances balance with the remaining allowances.

(2) If the sum of the proceeds to be distributed under paragraph (b) of this section is less than the total proceeds or the allowances to be reallocated under paragraph (c) of this section is less than the allowances remaining, then EPA will distribute one dollar or allowance for each unit, beginning with the unit receiving the largest number of dollars or allowances, in descending order, until the distribution balances with the proceeds and the reallocated allowances balance with the remaining allowances.

Subpart C—Allowance Tracking System

§ 73.30 Allowance tracking system accounts.

(a) *Nature and function of unit accounts.* The Administrator will establish accounts for all affected units pursuant to § 73.31 (a) and (b). All allocations of allowances pursuant to subparts B, E, and F of this part and part 72 of this chapter, transfers of allowances made pursuant to subparts C and D, and deductions of allowances made for purposes of offsetting emissions pursuant to § 73.35 (b) and (d) and parts 72, 75, and 77 of this chapter will be reordered in the unit's Allowance Tracking System account.

(b) *Nature and function of general accounts.* Transfers of allowances held for any person other than an affected unit, made pursuant to subparts C, D, E, F, and G of this part will be recorded in that person's Allowance Tracking System account established pursuant to § 73.31(c).

§ 73.31 Establishment of accounts.

(a) *Existing affected units.* The Administrator will establish an Allowance Tracking System account and allocate allowances for each unit that is, or will become, an existing affected unit pursuant to sections 404(a) or 405 of the Act and § 72.6 of this chapter.

(b) *New units.* Upon receipt of a complete certificate of representation for the designated representative for a new unit pursuant to part 72, subpart B of this chapter, the Administrator will establish an Allowance Tracking System account for the unit.

(c) *General accounts.* (1) Any person may apply to open an Allowance Tracking System account for the purpose of holding and transferring allowances. Such application shall be submitted to the Administrator in a format to be specified by the Administrator by means of the General Allowance Account Information Form, or by providing the following information in a similar format:

(i) Name and title of the authorized account representative and alternate

authorized account representative (if any) pursuant to § 73.33;

(ii) Mailing address, telephone number and facsimile transmission number (if any) of the authorized account representative and alternate authorized account representative (if any);

(iii) Organization or company name (if applicable) and type of organization (if applicable);

(iv) A list of all persons subject to a binding agreement for the authorized account representative to represent their ownership interest with respect to the allowances held in the general account and which shall be amended and resubmitted within 30 days following any transaction giving rise to any change of the list of persons subject to the binding agreement;

(v) A certification statement by the authorized account representative and alternate authorized account representative (if any) that reads "I certify that I was selected under the terms of an agreement that is binding on all persons who have an ownership interest with respect to allowances held in the Allowance Tracking System account. I certify that I have all necessary authority to carry out my duties and responsibilities on behalf of the persons with an ownership interest and that they shall be fully bound by my actions, inactions, or submissions under 40 CFR part 73. I shall abide by any fiduciary responsibilities assigned pursuant to the binding agreement. I am authorized to make this submission on behalf of the persons with an ownership interest for whom this submission is made. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false material information, or omitting material information, including the possibility of fine or imprisonment for violations.";

(vi) The signature of the authorized account representative and the alternate authorized account representative (if any); and

(vii) The date of the signature of the authorized account representative and the alternate authorized account representative (if any).

(2) Upon receipt of such complete application, the Administrator will establish an Allowance Tracking System account for the person or persons identified in the application.

(3) No allowance transfers will be recorded for a general account until the Administrator has established the new account.

(d) *Account identification.* The Administrator will assign a unique identifying number to each account established pursuant to this section.

§ 73.32 Allowance account contents.

Each allowance account will include, at a minimum, the following:

(a) The name, address, telephone number and facsimile transmission number, if any, of the authorized account representative; and

(1) In the case of a unit account, a list of all persons identified as owners of record of the unit in § 72.25(a)(3) of this chapter, or

(2) In the case of a general account, a list of all persons subject to the binding agreement for the authorized account representative to represent their ownership interest with respect to allowances, as identified in accordance with § 73.31(c);

(b) A list of transfers of allowances to, and from, the account, including the identity of the transferror and transferee accounts;

(c) In the case of a unit account for an existing affected unit, beginning in 1995, a compliance subaccount;

(d) In the case of a unit account for a new unit, a compliance subaccount;

(e) In the case of a general account, a current year subaccount;

(f) Future year subaccounts for each of the 30 calendar years following the later of 1995 or the current calendar year;

(g) In the case of a unit account, the current total of sulfur dioxide emissions in tons for the current calendar year as reported to date pursuant to part 75 of this chapter.

§ 73.33 Authorized account representative.

(a) Following the establishment of an Allowance Tracking System account, all matters pertaining to the account, including, but not limited to, the deduction and transfer of allowances in the account, shall be undertaken only by the authorized account representative.

(b) *Authorized account representative identification.* The Administrator will assign a unique identifying number to each authorized account representative or alternate authorized account representative identified pursuant to § 73.31(c).

(c) *Notification of parties subject to the binding agreement.* The authorized account representative for a general account shall notify, in writing, all persons who have an ownership interest with respect to the allowances held in the account of any Acid Rain Program submission required by this part or in a procedure under part 78 of this chapter, by the date of submission. Each person who has an ownership interest with respect to the allowances held in the account may expressly waive his or her right to receive such notification.

(d) *General account alternate authorized account representative.* Any application for opening a general account may designate one alternate authorized account representative to act on behalf of the certifying authorized account representative, in the event the authorized account representative is absent or otherwise not available to perform actions and duties under this part. The alternate shall be a natural person and shall be authorized, provided that the conditions and procedures specified in § 73.31(c)(1) are met.

(1) The alternate authorized account representative may be changed at any time by the authorized account representative upon receipt by the Administrator of a new complete application as required in § 73.31(c);

(2) The alternate authorized account representative shall be subject to the provisions of this part applicable to authorized account representatives;

(3) Whenever the term "authorized account representative" is used in this part it shall be construed to include the alternate authorized account representative, unless such a construction would be illogical from the context; and

(4) Any action, representation or failure to act by the alternate authorized account representative when acting in that capacity shall be deemed to be an action of the authorized account representative, with all the rights, duties, and responsibilities pertaining thereto.

(e) *Changes to the general account authorized account representative.* An authorized account representative for a general account may be succeeded by any person who submits an application pursuant to § 73.31(c). The actions of an authorized account representative for a general account shall be binding on any successor.

(f) *Objections to the authorized account representative.* Except for a certification pursuant to paragraph (e) of this section, no objection or other communication submitted to the Administrator concerning any submission to the Administrator by the authorized account representative shall affect the recordation of transfers submitted by the authorized account representative pursuant to subpart D of

this part. Neither the United States, the Administrator, nor any permitting authority will adjudicate any dispute between and among persons concerning any submission to the Administrator by the authorized account representative; any actions of the authorized account representative; or any other matter arising directly or indirectly from the certification, actions or representations of the authorized account representative.

§ 73.34 Recordation in accounts.

(a) *Recordation in compliance subaccounts.* At the beginning of 1995 and, in the case of each year thereafter, after the Administrator has made all deductions from an affected unit's compliance subaccount pursuant to § 73.35(b), the Administrator will record in the compliance subaccount the allowances held in the future year subaccount for the year corresponding to the current calendar year. The future year subaccount for the new 30th year will be established at the same time and include the allowances allocated for the unit for that year pursuant to subpart B of this part.

(b) *Recordation in current year subaccounts.* At the beginning of 1995 and each year thereafter, the Administrator will record in the current year subaccount the allowances held in the future year subaccount for the year corresponding to the current calendar year.

(c) *Recordation in subaccounts.* Allowances in each compliance, current year, and future year subaccounts will reflect:

(1) All allowances allocated or deducted for the unit for the year pursuant to subpart B of this part;

(2) All allowances allocated or deducted pursuant to § 72.41, § 72.42, § 72.43, and § 72.44 of this chapter;

(3) All allowances allocated pursuant to subparts F and G of this part;

(4) All allowances recorded as a result of purchases or returns from the annual auctions or direct sale pursuant to subpart E of this part;

(5) All allowances recorded or deducted as a result of allowance transfers recorded pursuant to subpart D of this part; and

(6) All allowances deducted or returned pursuant to § 73.35(d), §§ 72.91 and 72.92, and part 77 of this chapter.

(d) *Serial numbers for allocated allowances.* Upon the allocation of allowances to an account, including allowances contained in reserves as provided in subpart B of this part, the Administrator will assign each allowance a unique identification number that will include digits identifying the allowance's compliance use date.

§ 73.35 Compliance.

(a) *Allowance transfer deadline.* No allowance shall be deducted for purposes of compliance with an affected unit's sulfur dioxide Acid Rain emissions limitation requirements pursuant to title IV of the Act and paragraph (b) of this section unless:

(1) The compliance use date of the allowance is no later than the year in which the unit's SO_2 emissions occurred; and

(2) Such allowance is recorded in the compliance subaccount, or its transfer to the unit's compliance subaccount is submitted correctly pursuant to subpart D for recordation in the compliance subaccount for the unit by not later than the allowance transfer deadline of January 30 of the calendar year following the year for which compliance is being established in accordance with the requirements of subpart D of this part.

(b) *Deductions for compliance.* (1) Except as provided in paragraph (d) of this section, following the recordation of transfers submitted correctly pursuant to subpart D for recordation in the compliance subaccount pursuant to paragraph (a) of this section and subpart D of this part, the Administrator will deduct allowances from each affected unit's compliance subaccount in accordance with the allowance deduction formula in § 72.95 of this chapter and any correction made under § 72.96 of this chapter.

(2) The Administrator will make deductions until either the number of allowances deducted is equal to the amount calculated in accordance with § 72.95 of this chapter, as modified under § 72.96 of this chapter or until no more allowances remain in the compliance subaccount.

(c)(1) *Identification of allowances by serial number.* By no later than sixty days after the end of the calendar year, the authorized account representative for each unit account may identify by serial number the allowances to be deducted from the compliance subaccount for purposes of compliance with the unit's sulfur dioxide emissions limitation requirements. Such identification shall be made pursuant to part 72 of this chapter.

(2) *First-in, first-out.* In the absence of an identification or in the case of a partial identification of allowances by serial number, as provided for in paragraph (b)(1) or (d) of this section, the Administrator will deduct allowances on a first-in, first-out (FIFO) accounting basis beginning with those allowances with the earliest compliance use date originally allocated for the unit and recorded in its compliance subaccount. Following the deduction of all originally allocated allowances from the compliance subaccount, the Administrator will deduct those allowances that were transferred and recorded in the unit's compliance subaccount pursuant to subpart D of this part, beginning with those with the earliest date of recordation.

(d) *Deductions for excess emissions.* Pursuant to § 77.4 of this chapter, and following the process of recordation set forth in § 73.34(a) of this part, the Administrator will deduct allowances for each unit with excess emissions for the preceding calendar year in an amount equal to the unit's excess emissions tonnage.

(e) *Deductions for units sharing a common emission stack.* In the case of units sharing a common emission stack and have emissions that are not individually monitored pursuant to part 75 of this chapter, the authorized account representative may identify the percentage of allowances to be deducted from each unit's compliance subaccount. Such identification shall be made pursuant to part 72, subpart I of this chapter. In the absence of an identification, the Administrator will deduct an equal percentage of allowances from each unit's compliance subaccount.

§ 73.36 Banking.

(a) *Unit accounts.* Any allowance in a compliance subaccount not deducted pursuant to § 73.35 will remain in the compliance subaccount.

(b) *General accounts.* In the case of a general account, any allowances in the current year subaccount at the end of the current calendar year will remain in the current year subaccount.

§ 73.37 Account error and dispute resolution.

(a) *Claim of error.* The authorized account representative may notify the Administrator of any claim that the Administrator made an error in recording transfer information that was submitted correctly pursuant to subpart D of this part, provided that such claim of error notification is submitted to the Administrator by no later than 15 business days following the date mark of the notification by the Administrator pursuant to actions taken under § 73.37(d) or § 73.53. Such claim of error notification shall be in writing and shall include:

(1) A description of the error alleged to have been made by the Administrator;

(2) A proposed correction of the alleged error;

(3) Any supporting documentation or other information concerning the alleged error and proposed correction; and

(4) Certification by the signature of and the date of the signature of the authorized account representative.

The Administrator will not act on claim of error notifications received after the stated deadlines (except as provided under paragraph (f) of this section, or that do not contend that the Administrator made an error in recordation.

(b) *EPA action.* The Administrator, at the Administrator's sole discretion based on documentation provided, will determine what changes, if any, will be made to the accounts subject to the alleged error. Not later than 20 business days after receipt of a claim of error notification pursuant to paragraph (a) of this section, the Administrator will submit to the authorized account representative a written response stating:

(1) The determination made and any action taken by, the Administrator; and

(2) The reasons for such action.

(c) *Administrative Appeals Procedure.* Following the Administrator's action pursuant to paragraph (b) of this section, the authorized account representative may appeal the Administrator's action through the administrative appeals procedure pursuant to part 78 of this chapter.

(d) *EPA corrections.* The Administrator may, without prior notice of a claim of error and in the Administrator's sole discretion, correct any errors in any account on his or her own motion. The Administrator will notify the authorized account representative by no later than 20 business days following any such corrections.

(e) *Excess Emissions Requirements.* The filing of a claim of error notification pursuant to paragraph (a) of this section, or the pendency of the Administrator's action pursuant to paragraph (b) of this section, shall not affect a unit's obligations under part 77 of this chapter.

(f) *Waiver of Deadline.* The Administrator may, in his or her discretion, accept claim of error submissions made following the deadlines imposed in this section upon a demonstration by the authorized account representative of good cause for the delay. The finding of whether good cause exists shall be in the sole discretion of the Administrator. Appeals of a decision by the Administrator under this paragraph will be addressed pursuant to the administrative appeals process in part 78 of this chapter.

§ 73.38 Closing of accounts.

(a) *General Account.* The authorized account representative of a general account may instruct the Administrator to close the general account by submitting an allowance transfer, pursuant to § 73.50 and § 73.52, requesting the transfer of all allowances held in the account to one or more other accounts in the Allowance Tracking System, and by submitting in writing, with the signature of the authorized account representative, a request to delete the general account from the Allowance Tracking System.

(b) *Inactive accounts.* If a general account shows no activity for a period of a year or more and does not contain any allowances in its subaccounts, the Administrator will notify the account's authorized account representative that the account will be closed and eliminated from the Allowance Tracking System following 20 business days from the date the notice is sent. The account will be closed following the 20-day period, unless the Administrator receives and records a request for the transfer of allowances into the account pursuant to § 73.52 before the end of the 20-day period, or the authorized account representative submits, in writing, demonstration of good cause as to why the inactive account should not be closed. The finding of whether good cause exists shall be in the sole discretion of the Administrator.

Subpart D—Allowance Transfers

§ 73.50 Scope and submission of transfers.

(a) *Scope of transfers.* Except as provided in § 73.51 and § 73.52, the Administrator will record transfers of an allowance to and from Allowance Tracking System accounts, including, but not limited to, transfers of an allowance to and from contemporaneous future year subaccounts, and transfers of an allowance to and from compliance subaccounts and current year subaccounts, and transfers of all allowances allocated for a unit for each calendar year, in perpetuity.

(b) *Submission of transfers.* (1) Authorized account representatives seeking recordation of an allowance transfer shall request such transfer by submitting to the Administrator, in a format to be specified by the Administrator, an Allowance Transfer Form. To be considered correctly submitted the request for transfer shall include:

(i) The numbers identifying both the transferror and transferee accounts;

(ii) A specification by serial number of each allowance to be transferred, or correct indication on the allowance transfer where a request involves the transfer of the unit's allowances in perpetuity;

(ii) Signatures of the authorized account representatives of both the transferror and transferee accounts;

(iv) The dates of the signatures of the authorized account representatives;

(v) The numbers identifying the authorized account representatives for both the transferror and transferee account; and

(vi) Where the transferee account has not been established, information as required pursuant to § 73.31 (b) or (c).

(2) Transfers of allowances to or from compliance subaccounts submitted for recordation following the allowance transfer deadline will not be recorded until after completion of the process of recordation set forth in § 73.34(a).

§ 73.51 Prohibition.

Except as provided in § 73.34(a), the Administrator will not record a transfer of allowances from a future year subaccount to a subaccount for an earlier year.

§ 73.52 EPA recordation.

(a) *General recordation.* Except as provided in § 73.50, § 73.51, and this paragraph (a), the Administrator will record an allowance transfer by no later than five business days following receipt of an allowance transfer request pursuant to § 73.50, by moving each allowance from the transferror account to the transferee account as specified by the request pursuant to § 73.50, provided that:

(1) The information submitted pursuant to § 73.50 is complete;

(2) The transferror account includes each allowance identified by serial number in the allowance transfer request submitted pursuant to § 73.50, except when a request for transfer of the unit's allowances in perpetuity is indicated correctly on the allowance transfer submission;

(3) If the allowances identified by serial number specified pursuant to § 73.50(b)(1)(ii) are subject to the limitation on transfer imposed pursuant to § 72.44(h)(i), of this chapter, the transfer is in accordance with such limitation; and

(4) The transfer meets all applicable requirements of this subpart.

(b) Where an allowance transfer submitted for recordation fails to meet the requirements of this subpart, the Administrator will not record such transfer.

§ 73.53 Notification.

(a) *Notification of recordation.* The Administrator will notify each party to an allowance transfer within five business days following the recordation of the transfer. Notice will be given in writing or in a format to be specified by the Administrator, to the authorized account representatives of both the transferror and transferee accounts.

(b) *Notification of non-recordation.* By no later than five business days following receipt of an allowance transfer request by the Administrator, the Administrator will notify, in writing or in a format to be specified by the Administrator, the authorized account representatives of the accounts subject to the allowance transfer request submitted for recordation of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of an allowance transfer request for recordation following notification of non-recordation.

Subpart E—[Amended]

4. Section 73.72 Direct sales.

* * * * *

(c) *Price.* Allowances in the direct sale will be sold at $1,500 per allowance, adjusted by the Consumer Price Index (CPI). The following formula will be used each year to calculate the price:

$$\$1{,}500 \times \left(1 + \frac{\text{CPI (year)} - \text{CPI (1990)}}{\text{CPI (1990)}} \right)$$

* * * * *

5. Part 73 is amended by adding subpart F to read as follows:

Subpart F—Energy Conservation and Renewable Energy Reserve

73.80 Operation of allowance reserve program for conservation and renewable energy.
73.81 Qualified conservation measures and renewable energy generation.
73.82 Application for allowances from reserve program.
73.83 Secretary of Energy's action on net income neutrality applications.
73.84 Administrator's action on applications.
73.85 Administrator review of the reserve program.
73.86 State regulatory autonomy.

Appendix A to Subpart F—List of Qualified Energy Conservation Measures

Subpart F—Energy Conservation and Renewable Energy Reserve

§ 73.80 Operation of allowance reserve program for conservation and renewable energy.

(a) *General.* The Administrator will allocate allowances from the Conservation and Renewable Energy Reserve (the "Reserve") established under subpart B based on verified kilowatt hours saved through the use of one or more qualified energy conservation measures or based on kilowatt hours generated by qualified renewable energy generation. Allowances will be allocated to applicants that meet the requirements of this subpart according to the formulas specified in § 73.82(d), and in the order in which applications are received, except where provided for in § 73.84 and § 73.85, until a total of 300,000 allowances have been allocated.

(b) *Period of applicability.* Allowances will be allocated under this subpart for qualified energy conservation measures or renewable energy generation sources that are operational on or after January 1, 1993, and before the date on which any unit owned or operated by the applicant becomes a Phase I unit or a Phase II unit.

(c) *Termination of the Reserve.* The Administrator will reallocate any allowances remaining in the Reserve after January 2, 2010 to the affected units from whom allowances were withheld by the Administrator, in accordance with section 404(g), for purposes of establishing the Reserve. Each unit's allocation under this paragraph will be calculated as follows:

$$\frac{\text{Remaining allowances in the Reserve} \times \text{Unit's allowances withheld}}{\text{Total amount in Reserve}}$$

(Allowances will be rounded to the nearest allowance)

§ 73.81 Qualified conservation measures and renewable energy generation.

(a) *Qualified energy conservation measures.* A qualified energy conservation measure is a demand-side measure not operational until the period of applicability, implemented in the residence or facility of a customer to whom the utility sells electricity, that:

(1) Is specified in appendix A(1) of this subpart; or

(2) In the case of a device or material that is not included in appendix A(1) of this subpart,

(i) Is a cost-effective demand-side measure consistent with an applicable least-cost plan or least-cost planning process that increases the efficiency of the customer's use of electricity (as measured in accordance with § 73.82(c)) without increasing the use by the customer of any fuel other than qualified renewable energy, industrial waste heat, or, pursuant to paragraph (b)(5) of this section, industrial waste gases;

(ii) Is implemented pursuant to a conservation program approved by the utility regulatory authority, which certifies that it meets the requirements of paragraph (a)(2)(i) of this section and is not excluded by paragraph (b) of this section; and

(iii) Is reported by the applicant in its application to the Reserve.

(b) *Non-qualified energy conservation measures.* The following energy conservation measures shall not qualify for Allowance Reserve allocations:

(1) Demand-side measures that were operational before January 1, 1992;

(2) Supply-side measures;

(3) Conservation programs that are exclusively informational or educational in nature;

(4) Load management measures that lead to economic reduction of electric energy demand during a utility's peak generating periods, unless kilowatt hour savings can be verified by the utility pursuant to § 73.82(c); or

(5) Utilization of industrial waste gases, unless the applicant has certified that there is no net increase in sulfur dioxide emissions from such utilization.

(c) *Qualified renewable energy generation.* Qualified renewable energy generation is electrical energy generation, not operational until the period of applicability, that:

(1) Is specified in appendix A(3) of this subpart; or

(2) In the case of renewable energy generation that is not included in appendix A(3) of this subpart is:

(i) Consistent with a least cost plan or a least cost planning process and derived from biomass (*i.e.*, combustible energy-producing materials from biological sources which include wood,

plant residues, biological wastes, landfill gas, energy crops, and eligible components of municipal solid waste), solar, geothermal, or wind resources;

(ii) Implemented pursuant to approval by the utility regulatory authority, which certifies that it meets the requirements of paragraphs (c)(2)(i) and (c)(2)(ii) of this section and is not excluded by paragraph (d) of this section; and

(iii) Is reported by the applicant in its application to the Reserve.

(d) *Non-qualified renewable energy generation.* The following renewable energy generation shall not qualify for Allowance Reserve allocations:

(1) Renewable energy generation that was operational before January 1, 1992;

(2) Measures that reduce electricity demand for a utility's customers without providing electric generation directly for sale to customers; and

(3) Measures that appear on the list of qualified energy conservation measures in Appendix A(1) of this subpart.

§ 73.82 Application for allowances form reserve program.

(a) *Application Requirements.* Each application for Conservation and Renewable Energy Reserve allowances, shall:

(1) Certify that the applicant is a utility;

(2) Demonstrate that the applicant, any subsidiary of the applicant, or any subsidiary of the applicant's holding company, is an owner or operator, in whole or in part, of at least one Phase I or Phase II unit by including in the application the name and Allowance Tracking System account number of a Phase I or Phase II unit which it owns or operates and for which it is listed as an owner or operator on the certificate of representation submitted by the designated representative for the unit pursuant to § 72.20 of this chapter;

(3) Through certification, demonstrate that the applicant is paying in whole or in part for one or more qualified energy conservation measures or qualified renewable energy generation (that became operational during the period of applicability) either directly or through payment to another person that purchases the qualified energy conservation measure or qualified renewable energy generation;

(4) Demonstrate that the applicant is subject to a least cost plan or a least cost planning process that:

(i) provides an opportunity for public notice and comment or other public participation processes;

(ii) evaluates the full range of existing and incremental resources in order to meet expected future demand at lowest system cost;

(iii) treats demand-side resources and supply-side resources on a consistent and integrated basis;

(iv) takes into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk;

(v) may take into account other factors, including the social and environmental costs and benefits of resource investments; and

(vi) is being implemented by the applicant to the maximum extent practicable.

(5) Demonstrate that the qualified energy conservation measure adopted or qualified renewable energy generated, or both, are consistent with the least cost plan or least cost planning process;

(6) If the applicant is subject to the rate-making jurisdiction of a State or local utility regulatory authority, its least cost plan or least cost planning process has been approved or accepted by the utility regulatory authority in the State or locality in which the qualified conservation measure(s) are adopted or in which the qualified renewable energy generation is utilized, and such State or local utility regulatory authority certifies that the least-cost plan or least-cost planning process meets the requirements of paragraph (a)(4) of this section;

(7) If the applicant is not subject to the rate-making jurisdiction of a State or local regulatory authority, its least cost plan or least cost planning process has been approved or has been accepted by the utility regulatory authority with rate-making jurisdiction over the applicant, and such utility regulatory authority certifies that the least cost plan or least cost planning process meets the requirements of paragraph (a)(4) of this section;

(8) If the applicant is an independent power production facility that sells qualified renewable energy generation to another utility, the applicant has enclosed documentation that such qualified renewable energy generation was purchased pursuant to the purchasing utility's least cost plan or least cost planning process, which has been approved or accepted by the purchasing utility's utility regulatory authority.

(9)(i) If the applicant is an investor-owner utility subject to the ratemaking jurisdiction of a State utility regulatory authority and is submitting an application on the basis of one or more qualified energy conservation measures, such State utility regulatory authority has established a procedure for determining rates and charges ensuring net income neutrality, as defined in § 72.2 of this chapter, including a provision that the utility's net income is compensated in full (considering factors such as risk) for lost sales attributable to the utility's conservation programs, which may include:

(A) General ratemaking for formulas that decouple utility profits from actual utility sales;

(B) Specific rate adjustment formulas that allow a utility to recover in its retail rates the full costs of conservation measures plus any associated net revenues lost as a result of reduced sales resulting from conservation initiatives; or

(C) Conservation incentive mechanisms designed to provide positive financial rewards to a utility to encourage implementation of cost-effective measures;

(ii) Provided that the existence of any one of the categories of ratemaking or rate adjustment formulas or conservation incentive mechanisms specified in paragraph (a)(9)(i) of this section shall not necessarily constitute fulfillment of the net income neutrality requirement unless, pursuant to § 73.83, the Secretary of Energy has certified the establishment of such net income neutrality;

(10) Demonstrate that the applicant has implemented the qualified energy conservation measures or used the qualified renewable energy generation specified in the application during the period of applicability;

(11) Demonstrate the extent to which installation of the qualified conservation measure(s) has achieved actual energy savings, by stating, on the basis of the performance of the measure(s) following installation:

(i) The amount of kilowatt hour savings resulting from the measure(s) in the given year(s);

(ii) Pursuant to paragraph (c) of this section, the methodology used to calculate the kilowatt hour savings; and

(iii) The name, address, and phone number of the person who performed the calculation of kilowatt hour savings;

(12) Report the type and amount of yearly qualified renewable energy generation, by stating (and submitting documentation, including copies of plant operation records, supporting such statements) the kilowatt hours of qualified renewable energy generated during a previous calendar year or years; and

(13) Report the extent to which qualified renewable energy generation was produced in combination with other energy sources (hereafter "hybrid generation") by stating (and submitting documentation, including copies of plant operation records, supporting such statements) the heat input and heat

rate of the non-qualified renewable generation, the total annual kilowatt hours generated, and the kilowatt hours that can be attributed to qualified renewable energy generation;

(14) Demonstrate the extent to which the implementation of qualified energy conservation measures or the use of qualified renewable energy generation has resulted in avoided tons of sulfur dioxide emissions by the utility during the period of applicability, pursuant to paragraph (d) of this section.

(b) *Application to the Secretary of Energy.* For purposes of paragraph (a)(9) of this section, the applicant shall fulfill the following requirements:

(1) If a utility applying for allowances from the Reserve has not received certification of net income neutrality from the Secretary of Energy or such certification is no longer applicable, the applicant shall submit to the Secretary of Energy:

(i) A copy of the relevant State utility regulatory authority's final order or decision setting forth the approved ratemaking mechanisms that ensure that a utility's net income will be at least as high upon implementation of energy conservation measures as such net income would have been if the energy conservation measures has not been implemented;

(ii) A description of how the State utility regulatory authority's order or decision meets the definition of net income neutrality as defined in § 72.2; and

(iii) Any additional information necessary for Secretary of Energy to certify that the State regulatory authority has established rates and charges that ensure net income neutrality.

(2) If a utility applying for allowances from the Reserve has already received certification of net income neutrality from the Secretary of Energy in connection with a previous application for allowances, and the ratemaking methods or procedures that ensure net income neutrality have not been altered, the applicant shall certify that the ratemaking methods and procedures that led to the original certification are still in place.

(c) *Verification of energy savings methodology.* For the purposes of paragraph (a)(11) of this section:

(1) Applicants subject to the ratemaking jurisdiction of a State utility regulatory authority shall use the energy conservation verification methodology approved by such authority in support of energy conservation applications under this subpart and part 72 of this chapter, provided that

(i) The authority in question uses this methodology to determine the applicant's entitlement to performance-based rate adjustments, which permit a utility's rates to be adjusted for additional kilowatt hours saved due to the utility's energy conservation programs;

(ii) Such performance based rate adjustments are subject to modification either prospectively or retrospectively to reflect periodic evaluations of energy savings secured by the applicant; and

(iii) The applicant has provided the Administrator with a description of the State utility regulatory authority's verification methodology and documentation that the requirements of this paragraph (c) have been met.

(2) All other applicants, including applicants whose rates are not subject to the ratemaking jurisdiction of a State utility regulatory authority shall demonstrate to the satisfaction of the Administrator through submission of documentation that savings have been achieved and may use the EPA Conservation Verification Protocol.

(3) All records of verification of energy savings shall be kept on file by the applicant for a period of 3 years. The Administrator may extend this period for cause at any time prior to the end of 3 years by notifying the applicant in writing.

(4) The Administrator reserves the right to conduct independent reviews, analyses, or audits to ascertain that the verification is valid and correct. If the Administrator determines that the verification is not valid or correct, the Administrator may revise the allocation of allowances to an applicant or require the surrender of allowances from the applicant's Allowance Tracking System account.

(d) *Calculation of allowances to be allocated.*

(1) In the case of an application submitted on the basis of qualified energy conservation measures, the sulfur dioxide emissions tonnage deemed avoided for any calendar year shall be equal to the product of:

$$\frac{(A)\times(B)}{2000\ \text{lbs./ton}}$$

(Rounded to the nearest ton)

Where:

(A)=the kilowatt hours that were not, but would otherwise have been, supplied by the utility during such year in the absence of such qualified energy conservation measures.

(B)=0.004 lbs. of sulfur dioxide per kilowatt hour.

(2) In the case of an application submitted on the basis of qualified renewable energy generation, the sulfur dioxide emissions tonnage deemed avoided for any calendar year shall be equal to the product of:

$$\frac{(A)\times(B)}{2000\ \text{lbs./ton}}$$

(Rounded to the nearest ton)

Where:

(A)=the actual kilowatt hours of qualified renewable energy generated or purchased by the applicant (based on the qualified renewable energy generation portion for hybrid generation).

(B)=0.004 lbs. of sulfur dioxide per kilowatt hour.

(e) *Certification by Applicant's Certifying Official.*

(1) Certification of all application requirements, including the net income neutrality requirements, shall be made by a certifying official of the applicant upon such official's verification of all information and documentation submitted.

(2) The applicant shall submit a certification statement signed by the applicant's certifying official that reads "I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false material information, or omitting material information, including the possibility of fine or imprisonment for violations."

(f) *Certification by State Utility Regulatory Authority.* Applicants subject to the ratemaking jurisdiction of a State utility regulatory authority shall include in their applications a certification by the State utility regulatory authority's certifying official that it has reviewed the application, including supporting documentation, and finds it to be accurate, complete, and consistent with all applicable requirements of this subpart.

(g) *Time period to apply.* (1) Beginning no earlier than July 1, 1993, and no earlier than July 1 of each subsequent year, applicants may apply to the Administrator for allowances from the Reserve for emissions avoided in a previous year or years by use of qualified energy conservation measures or qualified renewable energy generation that became operational during the period of applicability; and

(2) Beginning no earlier than January 1, 1993, any applicant may apply to the Secretary of Energy for the Secretary's certification of net income neutrality where the application is based on the use of one or more qualified energy conservation measures.

(3) Applications will be received by the Administrator and the Secretary of Energy until January 2, 2010, pursuant to § 73.80(c), or until no allowances remain in the Reserve.

(h) *Submittal location.* Applicants shall submit one copy of the completed Reserve application, not including the net income neutrality application, via registered mail to the Administrator at an address to be specified in later guidance. Applicants shall submit 10 copies of the net income neutrality application via registered mail to the Department of Energy at the following address: Department of Energy, Office of Conservation and Renewable Energy, Mail Stop CE–10, Room 6c–036, 1000 Independence Avenue, SW., Washington, DC 20585, Attn: Net Income Neutrality Certification.

§ 73.83 Secretary of Energy's action on net income neutrality applications.

(a) *First come, first served.* The Secretary of Energy will process and certify net income neutrality applications on a "first-come, first served" basis, according to the order, by date and time, in which they are received from either the applicant or, in the case of an application submitted to the Administrator and then forwarded to the Secretary, from the Administrator.

(b) *Deficient applications.* If the Secretary of Energy determines that the net income neutrality certification application does not meet the requirements of § 73.82 (a)(9) and (b), the Secretary will notify the applicant and the Administrator in writing of the deficiency. The applicant may then supply additional information or a new revised application as necessary for the Secretary to make a determination that the applicant meets the requirements of § 73.28(a)(9) and (b). Additional information or revised applications will be processed according to the date of receipt of such information or revisions.

(c) *Notification of approval.* The Secretary of Energy will review the net income neutrality application to determine whether it meets the requirements of § 73.82 (a)(9) and (b) and will certify this finding in writing to the applicant and to the Administrator within 60 calendar days of receipt of the net income neutrality application or a revised application, except that the Secretary may specify a later date for certification.

§ 73.84 Administrator's action on applications.

(a) *First come, first served.* The Administrator will process and approve Allowance Reserve applications, in whole or in part, on a "first-come, first-served" basis as established by the order of date of receipt, provided that the Administrator shall not allocate more than a total of 30,000 allowances in connection with applications based on any one of the four categories of qualified renewable energy generation enumerated in § 73.81(c)(2)(i) and Appendix A(3.1–3.4).

(b) *Deficient applications.* An application is deficient and will be returned by the Administrator if it fails to meet the requirements set forth in this subpart, including those set forth in § 73.82. A revised application that is submitted after being returned for failure to meet the requirements of this subpart will be processed according to the date of receipt of the revised application.

(c) *Notification of approval.* Applications that the Administrator determines to be complete and correct will be conditionally approved, subject to notification to EPA of a net income neutrality certification from the Department of Energy, within 120 calendar days of receipt. Allowances from the Reserve will be awarded subject to the Department of Energy certification, or, if a DOE certification has already been issued to the applicant, allocated to applicants from such applications depending on the availability of allowances in the Reserve. In the event the initial application approval is conditioned upon the Secretary of Energy's certification, final approval will be granted upon notification of certification by the Secretary of Energy pursuant to § 73.83. The Administrator will notify applicants of final approval in writing.

(d) *Allocation of allowances.* Beginning in 1995, the Administrator will allocate allowances from the Reserve for each approved application into the applicant's account or accounts in the Allowance Tracking System. If the applicant does not have an account in the Allowance Tracking System, or wishes to open a new account for the allowances from the Reserve, an application pursuant to § 73.31(c) must accompany the application for Reserve allowances.

(e) *Partial fulfillment of requests.* (1) In the event that the allowances available in the Reserve are less than the number that could otherwise be allocated to an approved applicant's account under the application as approved, the applicant will receive the allowances remaining in the Reserve.

(2) In the event that a subaccount is established by EPA, pursuant to § 73.85, and the applicant is making a request for allowances not included in the subaccount, the Allowance Reserve allocations for the approved applicant will be made, in addition to any that may be allocated pursuant to paragraph (f)(3) of this section, from any allowances remaining in the Reserve that are not contained in the subaccount.

(f) *Oversubscription of the Reserve.*

(1) In the event that the Reserve becomes oversubscribed by more than one applicant on a single day, the allowances remaining in the Reserve will be distributed on a pro rata basis to applicants meeting the requirements of § 73.82.

(2) If Reserve applications are received by the Administrator after all allowances from the Reserve have been allocated, the Administrator will so notify the applicant within 5 business days after receipt of the application.

(3) In the event that applications meeting the requirements pursuant to § 73.82 are received by the Administrator prior to February 1, 1998, and

(i) All remaining allowances in the Reserve have been placed in a subaccount pursuant to § 73.85; and

(ii) The applicant is not eligible for an allocation of allowances from the subaccount; the application will be placed on a waiting list in order of receipt.

(iii) The Administrator will notify the applicant of such action within 5 business days after receipt of the application.

(4) If any allowances are returned to the Reserve after February 1, 1998 pursuant to § 73.85(c), the Administrator will review the wait-listed applications in order of receipt and allocate any remaining allowances to the approved applicants in the order of their receipt until no more allowances remain in the Reserve.

(g) *Applications for allowances based on the same avoided emissions from the same energy conservation measures or renewable energy generation.*

(1) The Administrator will not award allowances to more than one applicant for the same avoided emissions from the same energy conservation measure or the same qualified renewable energy generation, and will process and act on such duplicative applications on a "first-come, first-serve" basis as determined by the order of date of receipt.

(2) Any allowances awarded pursuant to two or more applications received on the same date based on the same avoided emissions from the same energy conservation measure or the same renewable electric generation will be divided equally between all such applicants unless the Administrator is otherwise directed by all such applicants.

§ 73.85 Administrator review of the reserve program.

(a) *Administrator review of the Reserve and creation of a subaccount.* In the event that an allocation of allowances from the Reserve pursuant to a pending application would bring the total number of allowances allocated to a number greater than 240,000, the Administrator will review the distribution of all allowances allocated as follows:

(1) If at least 60,000 allowances have been allocated from the Reserve for *each* of

(i) Qualified energy conservation measures, and

(ii) Qualified renewable energy generation, allocations of allowances will continue pursuant to § 73.82, until no more allowances remain in the Reserve.

(2) If fewer than 60,000 allowances have been allocated for either qualified energy conservation measures or qualified renewable energy generation, the Administrator will establish a subaccount for the allocation of allowances for applications based on the category for which fewer than 60,000 allowances have been allocated. The subaccount will contain allowances equal to 60,000 less the number of allowances previously allocated for such category.

(b) *Allocation of allowances from the subaccount.* The Administrator will allocate allowances from the subaccount established pursuant to paragraph (a) of this section to approved and DOE certified applicants that fulfill the requirements of this subpart, including § 73.82 and § 73.83, on a "first-come, first-served basis", pursuant to § 73.84(a), until the subaccount is depleted or closed pursuant to paragraph (c) of this section.

(c) *Closure of the subaccount.* Unless all allowances in the subaccount have been previously allocated, the Administrator will terminate the subaccount not later than February 1, 1998 and return any allowances remaining in the subaccount to the general account of the Reserve. After all Reserve allocations have been made to applicants with approved and DOE certified applications subject to § 73.84(f)(3), the Administrator will allocate any remaining allowances to any applicants that meet the requirements of this subpart, including § 73.82 and § 73.83, on a "first-come, first-served" basis, pursuant to § 73.84.

§ 73.86 State regulatory autonomy.

Nothing in this Subpart shall preclude a state or state regulatory authority from providing additional incentives to utilities to encourage investment in any conservation measures or renewable energy generation.

Appendix A to Subpart F—List of Qualified Energy Conservation Measures, Qualified Renewable Generation, and Measures Applicable for Reduced Utilization

1. Demand-side Measures Applicable for the Conservation and Renewable Energy Reserve Program or Reduced Utilization

The following listed measures are approved as "qualified energy conservation measures" for purposes of the Conservation and Renewable Energy Reserve Program or reduced utilization qualified energy conservation plans under § 72.43 of this chapter. Measures not appearing on the list may also be qualified conservation measures if they meet the requirements specified in § 73.81(a) of this part.

1.1 Residential

1.1.1 Space Conditioning

- Electric furnace improvements (intermittent ignition, automatic vent dampers, and heating element change-outs)
- Air conditioner (central and room) upgrades/replacements
- Heat pump (ground source, solar assisted, and conventional) upgrades/replacements
- Cycling of air conditioners and heat pumps
- Natural ventilation
- Heat recovery ventilation
- Clock thermostats
- Setback thermostats
- Geothermal steam direct use
- Improved equipment controls
- Solar assisted space conditioning (ventilation, air-conditioning, and desiccant cooling)
- Passive solar designs
- Air conditioner and heat pump clean and tune-up
- Heat pipes
- Whole house fans
- High efficiency fans and motors
- Hydronic pump insulation
- Register relocation
- Register size and blade configuration
- Return air location
- Duct sizing
- Duct insulation
- Duct sealing
- Duct cleaning
- Shade tree planting

1.1.2 Water Heating

- Electric water heater upgrades/replacements
- Electric water heater tank wraps/blankets
- Low-flow showerheads and fittings
- Solar heating and pre-heat units
- Geothermal heating and pre-heat units
- Heat traps
- Water heater heat pumps
- Recirculation pumps
- Setback thermostats
- Water heater cycling control
- Solar heating for swimming pools
- Pipe wrap insulation

1.1.3 Lighting

- Lamp replacement
- Dimmers
- Motion detectors and occupancy sensors
- Photovoltaic lighting
- Fixture replacement
- Outdoor lighting controls

1.1.4 Building Envelope

- Attic, basement, ceiling, and wall insulation
- Passive solar building systems
- Exterior roof insulation
- Exterior wall insulation
- Exterior wall insulation bordering unheated space (e.g., a garage)
- Knee wall insulation in attic
- Floor insulation
- Perimeter insulation
- Storm windows/doors
- Caulking/weatherstripping
- Multi-glazed inserts for sliding glass doors
- Sliding door replacements
- Installation of French doors
- Hollow core door replacement
- Radiant barriers
- Window vent conversions
- Window replacement
- Window shade screens
- Low-e windows
- Window reduction
- Attic ventilation
- Whole house fan
- Passive solar design

1.1.5 Other Appliances

- Refrigerator replacements
- Freezer replacements
- Oven/range replacements
- Dishwasher replacements
- Clothes washer replacements
- Clothes dryer replacements
- Customer located power generation based on photovoltaic, solar thermal, biomass, wind or geothermal resources
- Swimming pool pump replacements
- Gasket replacements
- Maintenance/coil cleaning

1.2 Commercial

1.2.1 Heating/Ventilation/Air Conditioning (HVAC)

- Heat pump replacement
- Fan motor efficiency
- Resizing of chillers
- Heat pipe retrofits in air conditioning units
- Dehumidifiers
- Steam trap insulation
- Radiator thermostatic valves
- Variable speed drive on fan motor
- Solar assisted HVAC including ventilation, chillers, heat pumps, and desiccants
- HVAC piping insulation
- HVAC ductwork insulation
- Boiler insulation
- Automatic night setback
- Automatic economizer cooling
- Outside air control

- Hot and cold deck automatic reset
- Reheat system primary air optimization
- Process heat recovery
- Deadband thermostat
- Timeclocks on circulating pumps
- Chiller system
- Increase condensing unit efficiency
- Separate make-up air for exhaust hoods
- Variable air volume system
- Direct tower cooling (chiller strainer cycle)
- Multiple chiller control
- Radiant heating
- Evaporative roof surface cooling
- Cooling tower flow control
- Ceiling fans
- Evaporative cooling
- Direct expansion cooling system
- Heat recovery ventilation (water and air-source)
- Set-back controls for heating/cooling
- Make-up air control
- Manual fan switches
- Energy saving exhaust hood
- Night flushing
- Spot radiant heating
- Terminal regulated air volume control scheme
- Variable speed motors for HVAC system
- Waterside economizers
- Airside economizer
- Gray water systems
- Well water for cooling

1.2.2 Building envelope
- Insulation
- Wall insulation
- Floor/slab insulation
- Roof insulation
- Window and door upgrades, replacements, and films (to reduce solar heat gains)
- Passive solar design
- Earth berming
- Shading devices and tree planting
- High reflectivity roof coating
- Evaporative cooling
- Infiltration reduction
- Weatherstripping
- Caulking
- Low-e windows
- Multi-glazed windows
- Replace glazing with insulated walls
- Thermal break window frames
- Tinted glazing
- Vapor barrier
- Vestibule entry

1.2.3 Lighting
- Electronic ballast replacements
- Delamping
- Reflectors
- Occupancy sensors
- Daylighting with controls
- Photovoltaic lighting
- Efficient exterior lighting
- Manual selective switching
- Efficient exit signs
- Daylighting construction
- Cathode cutout ballasts
- High intensity discharge luminaries
- Outdoor light timeclock and photocell

1.2.4 Refrigeration
- Refrigerator replacement
- Freezer replacement
- Optimize heat gains to refrigerated space
- Optimize defrost control
- Refrigeration pressure optimization control
- High efficiency compressors
- Anti-condensate heater control
- Floating head pressure
- Hot gas defrost
- Parallel unequal compressors
- Variable speed compressors
- Water cooler controls
- Waste heat utilization
- Air doors on refrigeration equipment

1.2.5 Water Heating
- Electric water heating upgrades/replacements
- Electric water heater wraps/blankets
- Pipe insulation
- Solar heating and/or pre-heat units
- Geothermal heating and/or pre-heat units
- Circulating pump control
- Point-of-use water heater
- Heat recovery domestic water heater (DWH) system
- Chemical dishwashing system
- End-use reduction using low-flow fittings

1.2.6 Other end-uses and miscellaneous
- Energy management control systems for building operations
- Customer located power based on photovoltaic, solar thermal, biomass, wind, and geothermal resources
- Energy efficient office equipment
- Customer-owned transformer upgrades and proper sizing

1.3 Industrial

1.3.1 Motors
- Retire inefficient motors and replace with energy efficient motors, including the use of electronic adjustable speed or variable frequency drives
- Rebuild motors to operate more efficiently through greater contamination protection and improved magnetic materials
- Install self-starters
- Replace improperly sized motors

1.3.2 Lighting
- Electronic ballast replacement/improvement
- Electromagnetic ballast upgrade
- Installation of reflectors
- Substitution of lamps with built-in automatic cathode cut-out switches
- Modify ballast circuits with additional impedance devices
- Metal halide and high pressure sodium lamp retrofits
- High pressure sodium retrofits
- Daylighting with controls
- Occupancy sensors
- Delamping
- Photovoltaic lighting
- Two step and dimmable high intensity discharge ballast

1.3.3 Heating/Ventilation/Air Conditioning (HVAC)
- Heat pump replacement/upgrade
- Furnace upgrade/replacement
- Fan motor efficiency
- Resizing of chillers
- Heat pipe retrofits on air conditioners
- Variable speed drive on fan motor
- Solar assisted HVAC including ventilation, chillers, heat pumps and desiccants

1.3.4 Industrial Processes
- Upgrades in heat transfer equipment
- Insulation and burner upgrades for industrial furnaces/ovens/boilers to reduce electricity loads on motors and fans
- Insulation and redesign of piping
- Upgrades/retrofits in condenser/evaporation equipment
- Process air and water filtration for improved efficiency
- Upgrades of catalytic combustors
- Solar process heat
- Customer located power based on photovoltaic, solar thermal, biomass, wind, and geothermal resources
- Power factor controllers
- Utilization of waste gas fuels
- Steam line and steam trap repairs/upgrades
- Compressed air system improvements/repairs
- Industrial process heat pump
- Optimization of equipment lubrication or maintenance
- Resizing of process equipment for optimal energy efficiency
- Use of unique thermodynamic power cycles

1.3.5 Building Envelope
- Insulation of ceiling, walls, and ducts
- Window and door replacement/upgrade, including thermal energy barriers
- Caulking/weatherstripping

1.3.6 Water Heating
- Electric water heater upgrades/replacements
- Electric water heater wraps/blankets
- Pipe insulation
- Low-flow showerheads and fittings
- Solar heating and pre-heat units
- Geothermal heating and pre-heat units

1.3.7 Other End-uses and miscellaneous
- Refrigeration system retrofit/replacement
- Energy management control systems and end use metering
- Customer-owned transformer retrofits/replacements and proper sizing

1.4 Agricultural

1.4.1 Space Conditioning
- Building envelope measures
- Efficient HVAC equipment
- Heat pipe retrofit on air conditioners
- System and control measures
- Solar assisted HVAC including ventilation, chillers, heat pumps, and desiccants
- Air-source and geothermal heat pumps replacement/upgrades

1.4.2 Water heating
- Upgrades/replacements
- Water heater wraps/blankets
- Pipe insulation
- Low-flow showerheads and fittings
- Solart heating and/or pre-hear units
- Geothermal heating and/or pre-heat units

1.4.3 Lighting
- Electronic ballast replacements
- Delamping
- Reflectors
- Occupancy sensors
- Daylighting with controls
- Photovoltaic lighting
- Outdoor lighting controls

1.4.4 Pumping/Irrigation
- Pump upgrades/retrofits
- Computerized pump control systems
- Irrigation load management strategies
- Irrigation pumping plants
- Computer irrigation control
- Surge irrigation
- Computerized scheduling of irrigation

• Drip irrigation systems
1.4.5 Motors
• Retire inefficient motors and replace with energy efficient motors, including the use of electronic adjustable speed and variable frequency drives
• Rebuild motors to operate more efficiently through greater contamination protection and improved magnetic materials
• Install self-starters
• Replace improperly sized motors
11.4.6 Other end uses
• Ventilation fans
• Cooling and refrigeration system upgrades
• Grain drying using unheated air
• Grain drying using low temperature electric
• Customer-owned transformer retrofits/replacements and proper sizing
• Programmable controllers for electrical farm equipment
• Controlled livestock ventilation
• Water heating for production agriculture
• Milk cooler heat exchangers
• Direct expansion/ice bank milk cooling
• Low energy precision application systems
• Heat pump crop drying
1.5 Government Services Sector
1.5.1 Streetlighting
• Replace incandescent and mercury vapor lamps with high pressure sodium and metal halide
1.5.2 Other
• Energy efficiency improvements in motors, pumps, and controls for water supply and waste water treatment
• District heating and cooling measures derived for cogeneration that result in electricity savings

2. Supply-side Measures Applicable for Reduced Utilization

Supply-side measures that may be approved for purposes of reduced utilization plans under § 72.43 include the following:
2.1 Generation efficiency
• Heat rate improvement programs
• Availability improvement programs
• Coal cleaning measures that improve boiler efficiency
• Turbine improvements
• Boiler improvements
• Control improvements, including artificial intelligence and expert systems
• Distributed control—local (real-time) versus central (delayed)
• Equipment monitoring
• Performance monitoring
• Preventive maintenance
• Additional or improved heat recovery
• Sliding/variable pressure operations
• Adjustable speed drives
• Improved personnel training to improve man/machine interface
2.2 Transmission and distribution efficiency
• High efficiency transformer switchouts using amorphous core and silicon steel technologies
• Low-loss windings
• Innovative cable insulation
• Reactive power dispatch optimization
• Power factor control
• Primary feeder reconfiguration
• Primary distribution voltage upgrades
• High efficiency substation transformers
• Controllable series capacitors
• Real-time distribution data acquisition analysis and control systems
• Conservation voltage regulation

3. Renewable Energy Generation Measures Applicable for the Conservation and Renewable Energy Reserve Program

The following listed measures are approved as "qualified renewable energy generation" for purposes of the Conservation and Renewable Energy Reserve Program. Measures not appearing on the list may also be qualified renewable energy generation measures if they meet the requirements specified in § 73.81.
3.1 Biomass resources
• Combustible energy-producing materials from biological sources which include: wood, plant residues, biological wastes, landfill gas, energy crops, and eligible components of municipal solid waste.
3.2 Solar resources
• Solar thermal systems and the non-fossil fuel portion of solar thermal hybrid systems
• Grid and non-grid connected photovoltaic systems, including systems added for voltage or capacity augmentation of a distribution grid.
3.4 Geothermal resources
• Hydrothermal or geopressurized resources used for dry steam, flash steam, or binary cycle generation of electricity.
3.5 Wind resources
• Grid-connected and non-grid-connected wind farms
• Individual wind-driven electrical generating turbines

(The information requirements in this subpart have been approved by the Office of Management and Budget under the control number 2060–0221.)

6. Title 40 is amended by adding part 75 to read as follows:

PART 75—CONTINUOUS EMISSION MONITORING

Subpart A—General

Sec.
75.1 Purpose and scope.
75.2 Applicability.
75.3 General Acid Rain Program provisions.
75.4 Compliance dates.
75.5 Prohibitions.
75.6 Incorporation by reference.
75.7 EPA Study.
75.8 [reserved].

Subpart B—Monitoring Provisions

75.10 General operating requirements.
75.11 Specific provisions for monitoring SO_2 emissions (SO_2 and flow monitors).
75.12 Specific provisions for monitoring NO_x emissions (NO_x and diluent gas monitors).
75.13 Specific provisions for monitoring CO_2 emissions.
75.14 Specific provisions for monitoring opacity.
75.15 Specific provisions for monitoring SO_2 emissions removal by qualifying Phase I technology.
75.16 Specific provisions for monitoring emissions from common, by-pass, and multiple stacks for SO_2 emissions and heat input determinations.
75.17 Specific provisions for monitoring emissions from common, by-pass, and multiple stacks for NO_x emission rate.
75.18 Specific provisions for monitoring emissions from common and by-pass stacks for opacity.

Subpart C—Operation and Maintenance Requirements

75.20 Certification and recertification procedures.
75.21 Quality assurance and quality control requirements.
75.22 Reference test methods.
75.23 Alternatives to ASTM methods.
75.24 Out-of-control periods.

Subpart D—Missing Data Substitution Procedures

75.30 General provisions.
75.31 Initial missing data procedures.
75.32 Determination of monitor data availability for standard missing data procedures.
75.33 Standard missing data procedures.
75.34 Units with add-on emission controls.

Subpart E—Alternative Monitoring Systems

75.40 General demonstration requirements.
75.41 Precision criteria.
75.42 Reliability criteria.
75.43 Accessibility criteria.
75.44 Timeliness criteria.
75.45 Daily quality assurance criteria.
75.46 Missing data substitution criteria.
75.47 Criteria for a class of affected units.
75.48 Petition for an alternative monitoring system.

Subpart F—Recordkeeping Requirements

75.50 General recordkeeping provisions.
75.51 General recordkeeping provisions for specific situations.
75.52 Certification, quality assurance and quality control record provisions.
75.53 Monitoring plan.

Subpart G—Reporting Requirements

75.60 General provisions.
75.61 Notification of certification and recertification test dates.
75.62 Monitoring plan.
75.63 Certification or recertification applications.
75.64 Quarterly reports.
75.65 Opacity reports.
75.66 Petitions to the Administrator.
75.67 Retired units petitions.
Appendix A to Part 75—Specifications and Test Procedures
Appendix B to Part 75—Quality Assurance and Quality Control Procedures
Appendix C to Part 75—Missing Data Statistical Estimation Procedures
Appendix D to Part 75—Optional SO_2 Emissions Data Protocol for Gas-Fired Units and Oil-Fired Units
Appendix E to Part 75—Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units
Appendix F to Part 75—Conversion Procedures

Appendix G to Part 75—Determination of CO_2 Emissions
Appendix H to Part 75—Revised Traceability Protocol No. 1
Appendix I to Part 75—Optional F-factor/Fuel Flow Method [reserved]

Authority: 42 U.S.C. 7651k and note.

Subpart A—General

§ 75.1 Purpose and scope.

(a) *Purpose.* The purpose of this part is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide, nitrogen oxides, and carbon dioxide emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to Sections 412 and 821 of the Clean Air Act, 42 U.S.C. 7401–7671q as amended by Public Law 101–549 [November 15, 1990] [the Act].

(b) *Scope.* The regulations established under this part include general requirements for the installation, certification, operation, and maintenance of continuous emission or opacity monitoring systems and specific requirements for the monitoring of SO_2 emissions, volumetric flow, NO_x emissions, opacity, CO_2 emissions and SO_2 emissions removal by qualifying Phase I technologies. Specifications for the installation and performance of continuous emission monitoring systems, certification tests and procedures, and quality assurance tests and procedures are included in Appendices A and B to this part. Criteria for alternative monitoring systems and provisions to account for missing data from certified continuous emission monitoring systems or approved alternative monitoring systems are also included in the regulation.

Statistical estimation procedures for missing data are included in appendix C to this part. Optional protocols for estimating SO_2 mass emissions from gas-fired or oil-fired units and NO_x emissions from gas-fired peaking or oil-fired peaking units are included in appendices D and E, respectively, to this part. Requirements for recording and recordkeeping of monitoring data and for quarterly electronic reporting also are specified. Procedures for conversion of monitoring data into units of the standard are included in appendix F to this part. Procedures for the monitoring and calculation of CO_2 emissions are included in appendix C of this part.

§ 75.2 Applicability.

(a) Except as provided in paragraph (b) of this section, the provisions of this part apply to each affected unit subject to Acid Rain emission limitations or reduction requirements for SO_2 or NO_x.

(b) The provisions of this part do not apply to:

(1) A new unit for which a written exemption has been issued under § 72.7 of this chapter (any new unit that serves one or more generators with total nameplate capacity of 25 MWe or less and burns only fuels with a sulfur content of 0.05 percent or less by weight may apply to the Administrator for an exemption); or

(2) An existing utility unit which serves a generator with nameplate capacity not greater than 25 MWe; or

(3) an existing simple combustion turbine; or

(4) An affected unit for which a written exemption has been issued under § 72.8 and an exception granted under § 75.67.

§ 75.3 General Acid Rain Program provisions.

The provisions of part 72, including the following, shall apply to this part:

(a) § 72.2 (Definitions);
(b) § 72.3 (Measurements, Abbreviations, and Acronyms);
(c) § 72.4 (Federal Authority);
(d) § 72.5 (State Authority);
(e) § 72.6 (Applicability);
(f) § 72.7 (New Unit Exemption);
(g) § 72.8 (Retired Units Exemption);
(h) § 72.9 (Standard Requirements);
(i) § 72.10 (Availability of Information); and
(j) § 72.11 (Computation of Time).

In addition, the procedures for appeals of decisions of the Administrator under this part are contained in part 78 of this chapter.

§ 75.4 Compliance dates.

(a) The provisions of this part apply to each existing Phase I and Phase II unit on February 10, 1993. For substitution or compensating units that are so designated under the acid rain permit which governs the unit and contains the approved substitution or reduced utilization plan, pursuant to § 72.41 or § 72.43 of this chapter, the provisions of this part become applicable upon the issuance date of the acid rain permit. In accordance with § 75.20, the owner or operator of each existing affected unit shall ensure that all certification tests for the required continuous emission monitoring systems and continuous opacity monitoring systems are completed not later than the following dates (except as provided in paragraphs (d) and (e) of this section):

(1) For Phase I unit, November 15, 1993.

(2) For a substitution or a compensating unit that is designated under an approved substitution plan or reduced utilization plan pursuant to § 72.41 or § 72.43 of this chapter, the later of the following dates:

(i) November 15, 1993; or

(ii) not later than 90 days after the issuance date (or date of approval of permit revision) of the acid rain permit which governs the unit and contains the approved substitution or reduced utilization plan.

(3) For a Phase II unit, January 1, 1995.

(b) In accordance with § 75.20, the owner or operator of each new affected unit shall ensure that all certification tests for the required continuous emission monitoring systems and continuous opacity monitoring systems are completed on or before the later of the following dates:

(1) January 1, 1995; or

(2) Not later than 90 days after the date the unit commences commercial operation, not to exceed the date the unit is declared commercial in accordance with DOE Form EIA–860 instructions (i.e., the date the unit is turned over to the dispatcher).

(c) In accordance with § 75.20, the owner or operator of an existing unit that did not serve a generator with a nameplate capacity greater than 25 MWe on November 15, 1990, but serves such a generator after November 15, 1990, shall ensure that all certification tests for the required continuous emission monitoring systems and continuous opacity monitoring systems are completed on or before the later of the following dates:

(1) January 1, 1995; or

(2) Not later than 90 days after the date the unit begins to serve a generator with a nameplate capacity greater than 25 MWe.

(d) In accordance with § 75.20, the owner or operator of an existing unit that is shut down and is not yet operating by the applicable dates listed in paragraph (a) of this section, shall ensure that all certification tests for the required continuous emission monitoring systems and continuous opacity monitoring systems are completed not later than 90 days after the date that the unit recommences commercial operation of the affected unit, not to exceed the date the unit is declared commercial in accordance with DOE Form EIA–860 instructions (i.e., the date the unit is turned over to the dispatcher).

(e) In accordance with § 75.20, the owner or operator of a unit with a qualifying Phase I technology which requires the use of an inlet SO_2-diluent continuous emission monitoring system for the purpose of monitoring SO_2 emissions removal from January 1, 1997

through December 31, 1999 shall ensure that all certification tests for the inlet and outlet SO_2-diluent continuous emission monitoring systems are completed no later than January 1, 1997.

§ 75.5 Prohibitions.

(a) A violation of any applicable regulation in this part by the owners or operators or the designated representative of an affected source or an affected unit is a violation of the Act.

(b) No owner or operator of an affected unit shall operate the unit without complying with the requirements of §§ 75.2 through 75.67 and appendices A through G of this part.

(c) No owner or operator of an affected unit shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained the Administrator's prior written approval in accordance with §§ 75.23, 75.48 and 75.66.

(d) No owner or operator of an affected unit shall operate the unit so as to discharge, or allow to be discharged, emissions of SO_2, NO_x, or CO_2 to the atmosphere without accounting for all such emissions in accordance with the provisions of §§ 75.10 through 75.18.

(e) No owner or operator of an affected unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO_2, NO_x, or CO_2 emissions discharged to the atmosphere, except for periods when maintenance is performed pursuant to § 75.21 and appendix B of this part.

§ 75.6 Incorporation by reference.

The materials listed in this section are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. These materials are incorporated as they existed on the date of approval, and a notice of any change in these materials will be published in the Federal Register. The materials are available for purchase at the corresponding address noted below and are available for inspection at the Office of the Federal Register, 800 N. Capitol Street, NW., Washington, DC, at the Public Information Reference Unit of the U.S. EPA, 401 M Street, SW., Washington, DC and at the Library (MD–35), U.S. EPA, Research Triangle Park, North Carolina.

(a) The following materials are available for purchase from the following addresses: American Society for Testing and Material (ASTM), 1916 Race Street, Philadelphia, Pennsylvania 19103; and the University Microfilms International 300 North Zeeb Road, Ann Arbor, Michigan 48106.

(1) ASTM D129–91, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), for appendices A and D of this part.

(2) ASTM D240–87 (Reapproved 1991), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, for appendices A, D, E and F of this part.

(3) ASTM D287–82 (Reapproved 1987), Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), for appendix D of this part.

(4) ASTM D388–92, Standard Classification of Coals by Rank, incorporation by reference for appendix F of this part.

(5) ASTM D941–88, Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Lipkin Bicapillary Pycnometer, for appendix D of this part.

(6) ASTM D1072–90, Standard Test Method for Total Sulfur in Fuel Gases, for appendix D of this part.

(7) ASTM D1217–91, Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer, for appendix D of this part.

(8) ASTM D1250–80 (Reapproved 1990), Standard Guide for Petroleum Measurement Tables, for appendix D of this part.

(9) ASTM D1298–85 (Reapproved 1990), Standard Practice for Density, Relative Density (Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, for appendix D of this part.

(10) ASTM D1480–91, Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer, for appendix D of this part.

(11) ASTM D1481–91, Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary Pycnometer, for appendix D of this part.

(12) ASTM D1552–90, Standard Test Method for Sulfur in Petroleum Products (High Temperature Method), for appendices A and D of the part.

(13) ASTM D1826–88, Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, for appendices E and F of this part.

(14) ASTM D1945–91, Standard Test Method for Analysis of Natural Gas by Gas Chromatography, for appendices F and G of this part.

(15) ASTM D1946–90, Standard Practice for Analysis of Reformed Gas by Gas Chromatography, for appendices F and G of this part.

(16) ASTM D2013–86, Standard Method of Preparing Coal Samples for Analysis, for appendix F of this part.

(17) ASTM D2015–91, Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter, for appendices, A, D, E and F of this part.

(18) ASTM D2234–89, Standard Test Methods for Collection of a Gross Sample of Coal, for appendix F of this part.

(19) ASTM D2382–88, Standard Test Method for Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), for appendices D, E and F of this part.

(20) ASTM D2502–87, Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements, for appendix G of this part.

(21) ASTM D2503–82 (Reapproved 1987), Standard Test Method for Molecular Weight (Relative Molecular Mass) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure, for appendix G of this part.

(22) ASTM D2622–92, Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry, for appendices A and D of this part.

(23) ASTM D3174–89, Standard Test Method for Ash in the Analysis Sample of Coal and Coke From Coal, for appendix G of this part.

(24) ASTM D3176–89, Standard Practice for Ultimate Analysis of Coal and Coke, for appendices A and F of this part.

(25) ASTM D3177–89, Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke, for appendix A of this part.

(26) ASTM D3178–89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, for appendix G of this part.

(27) ASTM D3238–90, Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n–d–M Method, for appendix G of this part.

(28) ASTM D4052–91, Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter, for appendix D of this part.

(29) ASTM D4057–88, Standard Practice for Manual Sampling of

Petroleum and Petroleum Products, for appendix D of this part.

(30) ASTM D4177–82 (Reapproved 1990), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, for appendix D of this part.

(31) ASTM D4239–85, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, for appendix A of this part.

(32) ASTM D4294–90, Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy, for appendices A and D of this part.

(b) The following materials are available for purchase from the American Society of Mechanical Engineers (ASME), 22 Law Drive, Box 2350, Fairfield, NJ 07007–2350.

(1) ASME MFC–3M–1989 with September 1990 Errata, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, for § 75.20 and appendices D and E of this part.

(2) ASME MFC–4M–1986 (Reaffirmed 1990), Measurement of Gas Flow by Turbine Meters, for § 75.20 and appendix E of this part.

(3) ASME MFC–5M–1985, Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, for § 75.20 and appendices D and E of this part.

(4) ASME MFC–6M–1987 with June 1987 Errata, Measurement of Fluid Flow in Pipes Using Vortex Flow Meters, for § 75.20 and appendices D and E of this part.

(5) ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, for § 75.20 and appendix E of this part.

(6) ASME MFC–9M–1988 with December 1989 Errata, Measurement of Liquid Flow in Closed Conduits by Weighing Method, for § 75.20 and appendices D and E of this part.

(7) ASME Power Test Code 4.1–1964 (Reaffirmed 1991), Steam Generating Units, for appendix E of this part.

(8) ASME Performance Test Code 17–1973 (Reaffirmed 1991), Reciprocating Internal Combustion Engines, for appendix E of this part.

(9) ASME Performance Test Code 22–1985, Gas Turbine Power Plants, for appendix E of this part.

§ 75.7 EPA Study.

The Agency will initiate rulemaking to adjust the equations in the bias test by an amount sufficient to compensate for reference monitor variance based on a study, which EPA shall complete by October 31, 1993, unless the Administrator determines that adjustments are technically unnecessary or infeasible to properly determine bias.

§ 75.8 [Reserved]

Subpart B—Monitoring Provisions

§ 75.10 General operating requirements.

(a) *Primary Measurement Requirement.* The owner or operator shall measure opacity, and all SO_2, NO_x, and CO_2 emissions for each affected unit as follows:

(1) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a SO_2 continuous emission monitoring system (consisting of an SO_2 pollutant concentration monitor and a flow monitor) with the automated data acquisition and handling system for measuring and recording SO_2 concentration (in ppm), volumetric gas flow (in scfh), and SO_2 mass emissions (in lb/hr) discharged to the atmosphere, except as provided in §§ 75.11 and 75.16 and subpart E;

(2) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a NO_x continuous emission monitoring system (consisting of a NO_x pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor) with the automated data acquisition and handling system for measuring and recording NO_x concentration (in ppm) and NO_x emission rate (in lb/mmbtu) discharged to the atmosphere, except as provided in §§ 75.12 and 75.17 and subpart E;

(3) The owner or operator shall determine CO_2 emissions by using one of the following options:

(i) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a CO_2 continuous emission monitoring system (consisting of a CO_2 pollutant concentration monitor and a flow monitor) with the automated data acquisition and handling system for measuring and recording CO_2 concentration (in ppm or percent, volumetric gas flow (in scfh), and CO_2 mass emissions (in tons/hr) discharged to the atmosphere;

(ii) The owner or operator shall determine CO_2 emissions based on the measured carbon content of the fuel and the procedures in Appendix G of this part to estimate CO_2 emissions (in ton/day) discharged to the atmosphere; or

(iii) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, an O_2 concentration monitor in order to determine CO_2 emissions using the procedures in appendix F of this part to measure CO_2 emissions (in tons/hr) and to estimate CO_2 emissions (in ton/day) discharged to the atmosphere; and

(4) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements in this part, a continuous opacity monitoring system with the automated data acquisition and handling system for measuring and recording the opacity of emissions (in percent opacity) discharged to the atmosphere, except as provided in §§ 75.14 and 75.18.

(b) *Primary Equipment Performance Requirements.* The owner or operator shall ensure that each continuous emission monitoring system required by this part meets the equipment, installation, and performance specifications in Appendix A to this part; and is maintained according to the quality assurance and quality control procedures in Appendix B to this part; and shall record SO_2 and NO_x emissions in the appropriate units of measurement (i.e., lb/hr for SO_2 and lb/mmBtu for NO_x).

(c) *Heat Input Measurement Requirement.* The owner or operator shall determine and record the heat input to each affected unit for every hour or part of an hour any fuel is combusted following the procedures in Appendix F to this part.

(d) *Primary Equipment Hourly Operating Requirements.* The owner or operator shall ensure that all continuous emission or opacity monitoring systems required by this part are in operation at all times that the affected unit combusts any fuel and that the following requirements are met:

(1) The owner or operator shall ensure that each continuous emission monitoring system and component thereof is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-min interval. The owner or operator shall reduce all SO_2 concentrations, volumetric flow, SO_2 mass emissions, SO_2 emission rate in lb/mmBtu (if applicable), CO_2 concentration, O_2 concentration, CO_2 mass emissions (if applicable), NO_x concentration, and NO_x emission rate data to 1-hr averages. The owner or operator shall compute these averages from four or more data points equally spaced over each 1-hr period, except during periods when calibration, quality assurance, or maintenance activities pursuant to § 75.21 and appendix B of this part are being performed. During these periods, a valid hour shall consist of at least two data points separated by a minimum of 15 minutes. For combined monitoring systems (NO_x-diluent and SO_2-diluent), the hourly average emission rate is valid

only if the hourly average concentration from each of the component monitors is valid.

(2) The owner or operator shall ensure that each continuous opacity monitoring system is capable of completing a minimum of one cycle of sampling and analyzing for each successive 10-sec period and one cycle of data recording for each successive 6-min period. The owner or operator shall reduce all opacity data to 6-min averages calculated from 36 or more data points equally spaced over each 6-min period, except where the applicable State implementation plan (pursuant to part 51, Appendix M of this chapter) or operating permit requires a different averaging period, in which case the State requirement shall satisfy this Acid Rain Program requirement.

(3) Failure of an SO_2 pollutant concentration monitor, flow monitor, or NO_x continuous emission monitoring system to acquire the minimum number of data points comprising a valid hour, as specified in paragraph (d) of this section shall result in the loss of such component data for the entire hour. The owner or operator shall estimate and record emission or flow data for the missing hour by means of the automated data acquisition and handling system, in accordance with the applicable procedure for missing data substitution in subpart D of this part.

(e) Optional Backup Monitor Requirements. If the owner or operator chooses to certify two or more continuous emission monitors or NO_x continuous emission monitoring systems that are each capable of monitoring a specific affected unit, or group of units using a common stack, then the owner or operator shall designate one such monitor or monitoring system as the primary monitor or monitoring system, and shall record this information in the monitoring plan, as provided for in § 75.53. The owner or operator shall designate the other certified monitor(s) or monitoring system(s) as the backup monitor(s) or monitoring system(s) in the monitoring plan. When the certified primary monitor or certified primary monitoring system is operating and not out-of-control as defined in § 75.24, only data from the certified primary monitor or certified primary monitoring system shall be reported as valid, quality-assured data. Thus, data from the certified backup monitor or certified backup monitoring system may be reported as valid, quality-assured data only when the backup is operating and not out-of-control as defined in § 75.24 *and* when the certified primary monitor or certified primary monitoring system is not operating (or is operating but out-of-control). A particular monitor may be designated both as a certified primary monitor for one unit and as a certified backup monitor for another unit.

(f) Minimum Measurement Capability Requirement. The owner or operator shall ensure that each continuous emission or opacity monitoring system and component thereof is capable of accurately measuring, recording, and reporting data, and shall not incur a full scale exceedance.

(g) Minimum Recording and Reporting Requirements. The owner or operator shall record and the designated representative shall report the hourly, daily, quarterly, and annual information collected under the requirements of this part as specified in subparts F and G of this part.

§ 75.11 Specific provisions for monitoring SO_2 emissions (SO_2 and flow monitors).

(a) *Coal-fired units.* The owner or operator shall meet the general operating requirements in § 75.10 for an SO_2 continuous emission monitoring system for each affected coal-fired unit, except as provided in § 75.16 and in subpart E of this part.

(b) *Moisture correction.* Where SO_2 concentration is measured on a dry basis, the owner or operator shall either:

(1) Install, operate, and maintain a continuous moisture monitor for measuring and recording the moisture content of the flue gases; or

(2) Determine the moisture content of the flue gases continuously (or on an hourly basis) and correct the measured hourly volumetric flow rates for moisture when calculating SO_2 mass emissions (in lb/hr) using the procedures in appendix F of this part.

(c) *Unit with no appropriate location for a flow monitor.* Where no location exists that satisfies the minimum physical siting criteria in appendix A to this part for installation of a flow monitor in either the stack or the ducts serving an affected unit or installation of a flow monitor in either the stack or ducts is demonstrated to the satisfaction of the Administrator to be technically infeasible, the owner or operator must either:

(1) Petition the Administrator for an alternative flow monitor location or alternative method for monitoring volumetric flow; or

(2) Construct a new stack or modify existing ductwork to accommodate the installation of a flow monitor, and petition the Administrator for an extension to the required certification date given in § 75.4 of this part. Phase I affected units may be granted an extension to January 1, 1995, for the submission of the certification application for the purpose of constructing a new stack or making substantial modifications to ductwork for installation of a flow monitor.

(d) *Gas-fired units and oil-fired units.* The owner or operator of an affected gas-fired or oil-fired unit shall measure and record SO_2 emissions using one of the following methods:

(1) Meet the general operating requirements in § 75.10 of this part for an SO_2 continuous emission monitoring system. When the owner or operator uses an SO_2 continuous emission monitoring system to monitor SO_2 mass emissions from an affected unit, the owner or operator shall comply with applicable monitoring provisions in paragraph (a) of this section; or

(2) Provide other information satisfactory to the Administrator using the procedure specified in appendix D to this part for estimating hourly SO_2 mass emissions.

(e) *Other units.* The owner or operator of an affected unit that combusts wood, refuse, or other material in addition to oil or gas shall comply with the monitoring provisions for coal-fired units specified in paragraph (a) of this section.

§ 75.12 Specific provisions for monitoring NO_x emissions (NO_x and diluent gas monitors).

(a) *Coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units.* The owner or operator shall meet the general operating requirements in § 75.10 of this part for a NO_x continuous emission monitoring system for each affected coal-fired unit, gas-fired nonpeaking unit, or oil-fired nonpeaking unit, except as provided in paragraph (c) of this section, § 75.17, and in subpart E of this part. The diluent gas monitor in the NO_x continuous emission monitoring system may measure either O_2 or CO_2 concentration in the flue gases.

(b) *Determination of NO_x emission rate.* The owner or operator shall calculate hourly, quarterly, and annual NO_x emission rates (in lb/mmBtu) by combining the NO_x concentration (in ppm) and diluent concentration (in percent O_2 or CO_2) measurements according to the procedures in appendix F of this part.

(c) *Gas-fired peaking units or oil-fired peaking units.* The owner or operator of an affected gas-fired peaking unit or oil-fired peaking unit shall comply with the following:

(1) If a unit's operations in the previous three calendar years are no more than a capacity fact or of 20 percent in each calendar year and no

more than an average capacity factor of 10 percent, then the owner or operator shall measure and record NO_x emissions using one of the following methods:

(i) Meet the general operating requirements in § 75.10 of this part for a NO_x continuous emission monitoring system; or

(ii) Provide information satisfactory to the Administrator using the procedure specified in appendix E of this part for estimating hourly NO_x emission rate.

(2) If a unit's operations in the previous three calendar years exceed a capacity factor of 20 percent in any calendar year or exceed an average capacity factor of 10 percent, the owner or operator shall install, certify, and operate a NO_x continuous emission monitoring system by December 31 of the following calendar year.

(3) When the owner or operator of an affected gas-fired peaking unit or oil-fired peaking unit uses a NO_x continuous emission monitoring system to monitor the NO_x emission rate from the unit, the owner or operator shall comply with the applicable monitoring provisions in paragraph (a) of this section.

(d) *Other units.* The owner or operator of an affected unit that combusts wood, refuse, or other material in addition to oil or gas shall comply with the monitoring provisions specified in paragraph (a) of this section.

§ 75.13 Specific provisions for monitoring CO_2 emissions.

(a) *CO_2 continuous emission monitoring system.* If the owner or operator chooses to use the continuous emission monitoring method, then the owner or operator shall meet the general operating requirements in § 75.10 of this part for a CO_2 continuous emission monitoring system for each affected unit. The owner or operator shall comply with the applicable provisions specified in § 75.11 (a) through (e) or § 75.16 of this part, except that the phrase "SO_2 continuous emission monitoring system" is replaced with "CO_2 continuous emission monitoring system," the term "SO_2 concentration" is replaced with "CO_2 concentration", and the phrase "SO_2 mass emissions" is replaced with "CO_2 mass emissions."

(b) *Determination of CO_2 emissions using Appendix G of this part.* If the owner or operator chooses to use the appendix G method, then the owner or operator may provide information satisfactory to the Administrator for estimating daily CO_2 mass emissions based on the measured carbon content of the fuel and the amount of fuel combusted. For units with wet flue gas desulfurization systems or other add-on emissions controls generating CO_2, the owner or operator shall use the procedures in appendix G to this part to estimate both combustion-related emissions based on the measured carbon content of the fuel and the amount of fuel combusted and sorbent-related emissions based on the amount of sorbent injected. The owner or operator shall calculate daily, quarterly, and annual CO_2 mass emissions (in tons) in accordance with the procedures in appendix G to this part.

(c) *Determination of CO_2 mass emissions using appendix F of this part.* If the owner or operator chooses to use the appendix F method, then the owner or operator may estimate hourly CO_2 mass emissions based on continuous O_2 concentration monitoring, fuel F and F_c factors, and where O_2 concentration is measured on a dry basis, hourly corrections for the moisture content of the flue gases, using the methods and procedures specified in appendix F to this part. For units using a common stack the owner or operator may use the provisions of § 75.16 of this part, except that the phrase "SO_2 continuous emission monitoring system" is replaced with "CO_2 continuous emission monitoring system," the term "SO_2 concentration" is replaced with "CO_2 concentration", and the phrase "SO_2 mass emissions" is replaced with "CO_2 mass emissions."

§ 75.14 Specific provisions for monitoring opacity.

(a) *Coal-fired units and oil-fired units.* The owner or operator shall meet the general operating provisions in § 75.10 of this part for a continuous opacity monitoring system for each affected coal-fired or oil-fired unit, except as provided in paragraphs (b), (c), and (d) of this section and in § 75.18. Each continuous opacity monitoring system shall meet the design, installation, equipment, and performance specifications in Performance Specification 1 in appendix B to part 60 of this chapter. Any continuous opacity monitoring system previously certified to meet Performance Specification 1 shall be deemed certified for the purposes of this part.

(b) *Unit with wet flue gas pollution control system.* If the owner or operator can demonstrate that condensed water is present in the exhaust flue gas stream and would impede the accuracy of opacity measurements, then the owner or operator of an affected unit equipped with a wet flue gas pollution control system for SO_2 emissions or particulates is exempt from the opacity monitoring requirements of this part.

(c) *Gas-fired units.* The owner or operator of an affected gas-fired unit is exempt from the opacity monitoring requirements of this part. Whenever a unit previously categorized as a gas-fired unit is recategorized as another type of unit by changing its fuel mix, the owner or operator shall install, operate, and certify a continuous opacity monitoring system as required by paragraph (a) of this section by December 31 of the following calendar year.

(d) *Diesel-fired units and dual-fuel reciprocating engines units.* The owner or operator of an affected diesel-fired unit or a dual-fuel reciprocating engine unit is exempt from the opacity monitoring requirements of this part.

§ 75.15 Specific provisions for monitoring SO_2 emissions removal by qualifying Phase I technology.

(a) *Additional monitoring provisions.* In addition to the SO_2 monitoring requirements in § 75.11 or § 75.16, for the purposes of adequately monitoring SO_2 emissions removal by qualifying Phase I technology operated pursuant to § 72.42 of this chapter, the owner or operator shall, except where specified below, use both an inlet SO_x-diluent continuous emission monitoring and an outlet SO_2-diluent continuous emission monitoring system, consisting of an SO_2 pollutant concentration monitor and a diluent CO_2 or O_2 monitor. (The outlet SO_2-diluent continuous emission monitoring system may consist of the same SO_2 pollutant concentration monitor that is required under § 75.11 or § 75.16 for the measurement of SO_2 emissions discharged to the atmosphere and the diluent monitor used as part of the NO_x continuous emission monitoring system that is required under § 75.12 or § 75.17 for the measurement of NO_x emissions discharged into the atmosphere.) During the period when required to measure emissions removal efficiency, from January 1, 1997 through December 31, 1991, the owner or operator shall meet the general operating requirements in § 75.10 of this part for both the inlet and the outlet SO_2-diluent continuous emission monitoring systems, and in addition, the owner or operator shall comply with the monitoring provisions in this section. On January 1, 2000, the owner or operator may cease operating and/or reporting on the inlet SO_2-diluent continuous emission monitoring system results for the purposes of the Acid Rain Program.

(1) *Pre-combustion technology.* The owner or operator of an affected unit for which a precombustion technology has been employed for the purpose of

meeting qualifying Phase I technology requirements shall use Reference Method 19 in appendix A to part 60 of this chapter to estimate, daily, the percentage SO_2 removal efficiency from such technology.

(2) *Combustion technology.* The owner or operator of an affected unit for which a combustion technology has been installed and operated for the purpose of meeting qualifying Phase I technology requirements shall use the coal sampling and analysis procedures in appendix F to this part and Equation 5 in paragraph (b) of this section to estimate the percentage SO_2 removal efficiency from such technology.

(3) *Post-combustion technology.* The owner or operator of an affected unit for which a post-combustion technology has been installed and operated for the purpose of meeting qualifying Phase I technology requirements shall install, certify, operate, and maintain both an inlet and an outlet SO_2-diluent continuous emission monitoring system.

(i) Both inlet and outlet SO_2-diluent continuous emission monitoring systems shall consist of an SO_2 pollutant concentration monitor and a diluent gas monitor for measuring the O_2 or CO_2 concentrations in the flue gas and shall measure and record average hourly SO_2 emission rates (in lb/mmBtu).

(ii) The SO_2-diluent continuous emission monitoring systems for measuring and recording the SO_2 emissions removal by a qualifying Phase I technology shall meet all the requirements of this part during the period when required to measure emissions removal, from January 1, 1997 through December 31, 1999, and shall meet the certification deadline specified in § 75.4.

(iii) The SO_2 pollutant concentration monitors and the diluent gas monitors at the inlet the outlet of the SO_2 emission controls shall meet all requirements specified in appendices A and B to this part.

(b) *Demonstration of SO^2 emissions removal efficiency.* The owner or operator shall demonstrate the average annual percentage SO_2 emissions removal efficiency of the installed technology or combination of technologies during the period when required to measure emissions removal, from January 1, 1997 through December 31, 1999, according to the following procedures:

(1) Calculate the average annual SO_2 emissions removal efficiency using Equations 1–7 as follows:

$$\%R = 100\{1.0-(1.0-\%R_f/100)\,(1.0-\%R_g/100)\,(1.0-\%R_c/100)\}$$ (*Eq.*1)

where,

%R = Overall percentage SO_2 emissions removal efficiency.

$\%R_f$ = Percentage SO_2 emissions removal efficiency from fuel pretreatment, calculated from Equation 19–22 in Reference Method 19 in Appendix A to part 60 of this chapter.

$\%R_c$ = Percentage SO_2 emissions removal of combustion emission controls, calculated from Equation 5.

$\%R_g$ = Percentage SO_2 removal efficiency of post-combustion emission controls, calculated from Equation 2.

$$\%R_g = 100\left[1.0-\frac{E_o}{E_i}\right]$$

(Eq.2)

where,

E_o=Average hourly SO_2 emission rate in lb/mmBtu, measured at the outlet of the post-combustion emission controls during the calendar year, calculated from Equation 3.

E_i=Average hourly SO_2 emission rate in lb/mmBtu, measured at the inlet to the post-combustion emission controls during the calendar year, calculated from Equation 4.

$$E_o = \frac{\sum_{j=1}^{n} E_{hoj}}{n}$$

(Eq. 3)

where,

E_{hoj}=Each hourly SO_2 emission rate in lb/mmBtu, measured by the continuous emission monitoring system at the outlet to the post-combustion emission controls.

n=Total unit operating hours during which the SO_2 continuous emission monitoring system at the outlet of the emission controls collected quality-assured data.

$$E_i = \frac{\sum_{j=1}^{m} E_{hij}}{m}$$

(Eq. 4)

where,

E_{hij}=Each hourly SO_2 emission rate in lb/mmBtu, measured by the continuous emission monitoring system at the inlet to the post-combustion emission controls.

m=Total unit operating hours during which the SO_2 continuous emission monitoring system at the inlet to the emission controls collected quality-assured data.

$$\%R_c = 100\left[1.0-\frac{E_{co}}{E_{ci}}\right]$$

(Eq. 5)

where,

E_{co}=Average hourly SO_2 emission rate in lb/mmBtu, measured at the outlet of the combustion emission controls during the calendar year, calculated from Equation 6.

E_{ci}=Average hourly SO_2 emission rate in lb/mmBtu, determined by coal sampling and analysis according to the methods and procedures in Appendix G, Section 2.5.4 of this part, calculated from Equation 7.

$$E_{co} = \frac{\sum_{j=1}^{q} E_{ocj}}{q}$$

(Eq. 6)

where,

E_{ocj}=Each hourly SO_2 emission rate in lb/mmBtu, measured by the continuous emission monitoring system at the outlet to the combustion controls.

q=Total unit operating hours for which the outlet SO_2 continuous emission monitoring system collected quality-assured data during the calendar year.

$$E_{ci} = \frac{\sum_{j=1}^{p} E_{icj}}{p}$$

(Eq. 7)

where,

E_{icj}=Each average hourly SO_2 emission rate in lb/mmBtu, determined by the coal sampling and analysis methods and procedures in Appendix G, Section 2.5.4 of this part and calculated using Appendix A, Method 19 of part 60 of this chapter, performed once a day.

p=Total unit operation hours during which coal sampling and analysis is performed to determine SO_2 emissions at the inlet to the combustion controls.

(2) The owner or operator shall include all periods when fuel is being combusted in determining total unit operating hours for the purpose of calculating the average SO_2 emissions removal efficiency during the calendar year.

(3) The owner or operator shall use only quality-assured SO_2 emissions data in the calculation of SO_2 emissions removal efficiency.

(4) Compliance with the 90-percent SO_2 emissions removal efficiency requirement under this part is

determined annually beginning January 1, 1997 through December 31, 1999.

§ 75.16 Special provisions for monitoring emissions from common by-pass, and multiple stacks for SO_2 emissions and heat input determinations.

(a) *Phase I common stack procedures.* During Phase I of the Acid Rain Program, the following procedures shall be used when more than one unit utilize a common stack:

(1) *Unit utilizing common stack with other Phase I units(s).* When a Phase I affected unit uses a common stack with one or more other Phase I affected units, but no other units, the owner or operator shall either:

(i) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the duct to the common stack from each affected unit; or

(ii) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the common stack; and

(A) Combine emissions for the affected units for compliance purposes; or

(B) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning SO_2 mass emissions measured in the common stack to each of the Phase I affected units. The Administrator may approve such demonstrated substitute methods for apportioning SO_2 mass emissions measured in a common stack whenever the demonstration ensures complete and accurate accounting of all emissions regulated under this part.

(2) *Unit utilizing common stack with non-Phase I unit(s).* When one or more Phase I affected units uses a common stack with one or more Phase II or nonaffected units, the owner or operator shall either:

(i) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the duct to the common stack from each Phase I unit; or

(ii) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the common stack; and

(A) Designate the Phase II units as substitution units according to the procedure in part 72 of this chapter and the nonaffected units as opt-in units in accordance with the regulations implementing section 410 of the Act and combine emissions for compliance purposes; or

(B) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the duct from each Phase II or nonaffected unit; determine SO_2 mass emissions from the affected units as the difference between SO_2 mass emissions measured in the common stack and SO_2 mass emissions measured in the ducts of the Phase II and/or nonaffected units; and combine emissions for the Phase I affected units for compliance purposes; or

(C) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning SO_2 mass emissions measured in the common stack to each of the units using the common stack. The Administrator may approve such demonstrated substitute methods for apportioning SO_2 concentration measured in a common stack whenever the demonstration ensures complete and accurate accounting of all emissions regulated under this part.

(b) *Phase II common stack procedures.* During Phase II of the Acid Rain Program, the following procedures shall be used when more than one unit use a common stack:

(1) *Unit utilizing common stack with other affected units(s).* When a Phase I or Phase II affected unit utilizes a common stack with one or more other Phase I or Phase II affected units, but no nonaffected units, the owner or operator shall either:

(i) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the duct to the common stack from each affected unit; or

(ii) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the common stack; and

(A) Combine emissions for the affected units for compliance purposes; or

(B) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning SO_2 mass emissions measured in the common stack to each of the Phase I and Phase II affected units. The Administrator may approve such demonstrated substitute methods for apportioning SO_2 mass emissions measured in a common stack whenever the demonstration ensures complete and accurate accounting of all emissions regulated under this part.

(2) *Unit utilizing common stack with nonaffected unit(s).* When one or more Phase I or Phase II affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either:

(i) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the duct to the common stack from Phase I and Phase II unit; or

(ii) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the common stack; and

(A) Designate the nonaffected units as opt-in units in accordance with the regulations implementing section 410 of the Act and combine emissions for compliance purposes; or

(B) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the duct from each nonaffected unit; determine SO_2 mass emissions from the affected units as the difference between SO_2 mass emissions measured in the common stack and SO_2 mass emissions measured in the ducts of the nonaffected units; and combine emissions for the Phase I and Phase II affected units for compliance purposes; or

(C) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning SO_2 mass emissions measured in the common stack to each of the units using the common stack. The Administrator may approve such demonstrated substitute methods for apportioning SO_2 concentration measured in a common stack whenever the demonstration ensures complete and accurate accounting of all emissions regulated under this part.

(c) *Unit with by-pass stack.* When any portion of the flue gases from an affected unit can be routed so as to avoid the installed SO_2 continuous emission monitoring system, the owner or operator shall install, certify, operate, and maintain an SO_2 continuous emission monitoring system on the by-pass flue, duct, or stack gas stream.

(d) *Unit with multiple stacks.* When the flue gases from an affected unit utilize two or more ducts feeding into two or more stacks (that may include flue gases from other affected or nonaffected units), the owner or operator shall either:

(1) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in each duct feeding into the stacks and determine SO_2 mass emissions from each affected unit as the sum of the SO_2 mass emissions measured in the ducts; or

(2) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in each stack and develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning measured SO_2 mass emissions to each affected unit. The Administrator may approve such demonstrated substitute methods for

apportioning measured SO_2 mass emissions from multiple stacks whenever the demonstration ensures complete and accurate accounting of all emissions regulated by this part.

(e) *Heat Input.* The owner or operator of an affected unit using a common stack with a diluent monitor and a flow monitor may choose to determine the heat input for the affected unit, wherever flow and diluent monitor measurements are used to determine the heat input, using the procedures specified in paragraphs (a) through (d) of this section, except that the terms "SO_2 mass emissions" or "emissions" are replaced with the term "heat input" and the phrase "SO_2 continuous emission monitoring system" is replaced with the phrase "a diluent monitor and a flow monitor".

§ 75.17 Specific provisions for monitoring emissions from common, by-pass, and multiple stacks for NO_x emission rate.

(a) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more affected units, but no nonaffected units, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_x continuous emission monitoring system in the duct to the common stack from each affected unit; or

(2) Install, certify, operate, and maintain a NO_x continuous emission monitoring system in the common stack and follow the appropriate procedure in paragraphs (a)(2) (i) through (iii) of this section, depending on whether or not the units are required to comply with a NO_x emission limitation (in lb/mmBtu, annual average basis) pursuant to section 407(b) of the Act (referred to hereafter as "NO_x emission limitation").

(i) When each of the affected units has a NO_x emission limitation, the designated representative shall submit a compliance plan to the Administrator that indicates:

(A) Each unit will comply with the most stringent NO_x emission limitation of any unit utilizing the common stack; or

(B) Each unit will comply with the applicable NO_x emission limitation by averaging its emissions with the other unit(s) utilizing the common stack.

(ii) When none of the affected units has a NO_x emission limitation, the owner or operator and the designated representative have no additional obligations pursuant to section 407 of the Act and may record and report a combined NO_x emission rate (in lb/mmBtu) for the affected units utilizing the common stack.

(iii) When at least one of the affected units has a NO_x emission limitation and at least one of the affected units does not have a NO_x emission limitation, the owner or operator shall either:

(a) Install, certify, operate, and maintain NO_x and diluent monitors in the ducts from the affected units; or

(B) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined NO_x emission rate (in lb/mmBtu) measured in the common stack on each of the units. The Administrator may approve such demonstrated substitute methods for apportioning NO_x emission rate measured in a common stack whenever the demonstration ensures complete and accurate estimation of all emissions regulated under this part.

(b) *Unit utilizing common stack with nonaffected units(s).* When one or more affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_x continuous emission monitoring system in the duct from each affected unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined NO_x emission rate (in lb/mmBtu) measured in the common stack for each of the units. The Administrator may approve such demonstrated substitute methods for apportioning NO_x emission rate measured in a common stack whenever the demonstration ensures complete and accurate estimation of all emissions regulated under this part.

(c) *Unit with by-pass stack.* When any portion of the flue gases from an affected unit can be routed so as to by-pass the installed NO_x continuous emission monitoring system, the owner or operator shall install, certify, operate, and maintain a NO_x continuous emission monitoring system on the by-pass flue, duct, or stack gas stream.

(d) *Unit with multiple stacks.* When the flue gases from an affected unit utilize two or more ducts feeding into two or more stacks (that may include flue gases from other affected or nonaffected units), the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_x continuous emission monitoring system in each duct feeding into the stacks and determine the NO_x emission rate for the unit as the Btu-weighted sum of the NO_x emission rates measured in the ducts using the heat input estimation procedures in appendix F to this part; or

(2) Install, certify, operate, and maintain a NO_x continuous emission monitoring system in each stack and develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning measured NO_x emission rates to each affected unit. The Administrator may approve such demonstrated substitute methods for apportioning measured NO_x emission rates from multiple stacks whenever the demonstration ensures complete and accurate accounting of all emissions regulated by this part.

§ 75.18 Specific provisions for monitoring emissions from common and by-pass stacks for opacity.

(a) *Unit using common stack.* When an affected unit utilizes a common stack with other affected units or nonaffected units, the owner or operator shall comply with the applicable monitoring provision in this paragraph, as determined by existing Federal, State, or local opacity regulations.

(1) Where another regulation requires the installation of a continuous opacity monitoring system upon each affected unit, the owner or operator shall install, certify, operate, and maintain a continuous opacity monitoring system meeting Performance Specification 1 in appendix B to part 60 of this chapter (referred to hereafter as a "certified continuous opacity monitoring system") upon each unit.

(2) Where another regulation does not require the installation of a continuous opacity monitoring system upon each affected unit, and where the affected source is not subject to any existing Federal, State, or local opacity regulations, the owner or operator shall install, certify, operate, and maintain a certified continuous opacity monitoring system upon each common stack for the combined effluent.

(b) *Unit with by-pass stack.* Where any portion of the flue gases from an affected unit can be routed so as to by-pass the installed continuous opacity monitoring system, the owner or operator shall install, certify, operate, and maintain a continuous opacity monitoring system on the by-pass flue, duct, or stack gas stream.

Subpart C—Operation and Maintenance Requirements

§ 75.20 Certification and recertification procedures.

(a) *Initial certification approval process.* The owner or operator shall ensure that each continuous emission or opacity monitoring system required by this part, the automated data acquisition and handling system, and, where

applicable, the CO_2 continuous emission monitoring system meets the certification requirements of this section by the deadlines specified in § 75.4 of this part and prior to use in the Acid Rain Program.

(1) *Notificaiton of certification test dates or certification retesting dates.* The owner or operator or designated representative shall submit a written notice of the dates of certification testing at least 45 calendar days prior to the first day of certification testing, as specified in §§ 75.60 and 75.61.

(i) Except as provided in paragraph (a)(1)(ii) of this section, the owner or operator or designated representative shall also submit notification (or provide notification by telephone) at least 7 business days in advance of any proposed adjustments to the certification test dates.

(ii) The owner or operator may elect to repeat a certification test immediately, without advance notification, whenever the owner or operator has determined during the certification testing that a continuous emission or opacity monitoring system or component thereof has failed the test.

(2) *Certification Application.* The designated representative shall apply for certification of each continuous emission or opacity monitoring system used under the Acid Rain Program. The designated representative shall submit the certification application in accordance with § 75.60 and each complete certification application shall include the information specified in § 75.63 of this part.

(3) *Provisional approval of certification applications.* Upon the successful completion of the required certification procedures for each continuous emission or opacity monitoring system or component thereof and subsequent submittal of a complete certification application in accordance with § 75.63, each continuous emission or opacity monitoring system or component thereof shall be deemed provisionally certified for use under the Acid Rain Program for a period not to exceed 120 days following receipt by the Administrator of the complete certification application. Data measured and recorded by a provisionally certified continuous emission or opacity monitoring system or component thereof, in accordance with the requirements of appendix B of this part, will be considered valid quality-assured data (retroactive to the date and time of completion of the certification tests), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application.

(4) *Certification application formal approval process.* The Administrator will issue a written notice of certification application status to the owner or operator within 120 days of receipt of the complete certification application. In the event the Administrator does not issue a written notice of certification application status within 120 days of receipt, each continuous emission or opacity monitoring system which meets the performance requirements of this part and is included in the certification application will be deemed certified for use under the Acid Rain Program.

(i) *Approval notice.* If the certification application is complete and shows that each continuous emission or opacity monitoring system meets the performance requirements of this part, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(ii) *Incomplete application notice.* If the certification application is not complete, then the Administrator will issue a written notice of insufficiency. The 120-day review period shall not begin prior to receipt of a complete application.

(iii) *Disapproval notice.* If the certification application is complete but shows that any continuous emission or opacity monitoring system or component thereof does not meet the performance requirements of this part, the Administrator shall issue a written notice of disapproval of the certification application within 120 days of receipt. By issuing the notice of disapproval, the provisional certification is invalidated by the Administrator, and the data measured and recorded by each uncertified continuous emission or opacity monitoring system or component thereof shall not be considered valid quality-assured data from the date and time of completion of the invalid certification tests until the date and time that the owner or operator completes subsequently approved initial certification tests. The owner or operator shall follow the loss of certification procedures in paragraph (a)(5) of this section to replace all of the invalid data for each continuous emission or opacity monitoring system or component which was disapproved.

(iv) *Audit decertifications.* Whenever an audit of a continuous emission or opacity monitoring system or component thereof or of the certification application reveals that any continuous emission or opacity monitoring system or component does not meet the performance requirements of this part (after the initial 120-day certification application review period), the Administrator may issue a notice of disapproval of the certification status of such system or component. By issuing the notice of disapproval, the certification status is invalidated, prospectively, by the Administrator, and the data measured and recorded by each continuous emission or opacity monitoring system from the date of the notification of the invalid certification status until the date and time that the owner or operator completes subsequently approved initial certification tests shall not be considered valid quality-assured data. The owner or operator shall follow the loss of certification procedures in paragraph (a)(5) of this section to replace, prospectively, all of the invalid data for each continuous emission or opacity monitoring system or component which was disapproved.

(5) *Loss of Certification Procedures.* When the Administrator issues a notice of disapproval of a certification application or a notice of disapproval of certification status, then for the period of invalid data (as specified in paragraph (a)(4) of this section), the owner or operator shall:

(i) Use the maximum potential concentration of SO_2 or NO_x, or the maximum potential velocity, as defined in section 2.1 of appendix A of this part, or the minimum O_2 concentration or maximum CO_2 concentration used to determine the maximum potential concentration of SO_2 in section 2.1.1.1 of appendix A of this part to report SO_2 concentration, NO_x concentration, calculate and report volumetric flow rate, or O_2 or CO_2 concentration data until such time, date, and hour as the continuous emission monitoring system or component thereof can be adjusted, repaired, or replaced and certification tests successfully completed (a subsequently approved initial certification); and

(ii) Ensure that the owner or operator or designated representative submits a notification of certification test dates and a new certification application according to the procedures in paragraphs (a)(1)(ii) and (a)(2) of this section, where the notification shall be provided no later than 2 business days prior to retesting for certification.

(b) *Recertification approval process.* Whenever the owner or operator makes a replacement, modification, or change in the certified continuous emission monitoring system or continuous opacity monitoring system, including the automated data acquisition and

handling system, that significantly affects the ability of the system to measure or record the SO_2 concentration, volumetric gas flow, SO_2 mass emissions, NO_x emission rate, CO_2 concentration, or opacity, the owner or operator shall recertify the continuous emission monitoring system, continuous opacity monitoring system, or component according to the procedures in this paragraph. Replacement of the analytical method, including the analyzer; change in location or orientation of the sampling probe or site; rebuilding of equipment; and analytical modifications to computer algorithms in software systems require recertification. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system that significantly affects the ability of the CEM or COM or component thereof to measure or record SO_2, NO_x, CO_2, or opacity emissions, the owner or operator shall recertify the CEM or COM or component according to the procedures in this paragraph. Recertification is not required in cases where all of the following conditions have been met: a continuous emission monitoring system has previously been certified with the same sampling location; all components of the continuous emissions monitoring system have previously been certified; and component monitors that have changed location (i.e., certified portable monitors) pass a linearity check (for pollutant concentration monitors) or a calibration error test (for flow monitors) prior to their use for monitoring of emissions or flow.

However, changes resulting from routine or normal corrective maintenance and/or quality assurance activities do not require recertification, nor do software modifications in the automated data acquisition and handling system, where the modification is only for the purpose of generating additional or modified reports for the State Implementation Plan or for reporting requirements under subpart G of this part.

(1) *Notification of recertification test dates.* For a recertification test, the owner or operator or designated representative shall submit the notification in accordance with the provisions in paragraph (a)(1) of this section except when recertification testing results from an emergency situation, in which case, the owner or operator or designated representative may submit notice (or provide notification by telephone) no later than 2 business days following the emergency, identifying when the testing has been or will be completed.

(2) *Recertification application.* The designated representative shall apply for recertification of a continuous emission or opacity monitoring system used under the Acid Rain Program according to the procedures in paragraph (a)(2) of this section.

(3) *Approval/disapproval of request for recertification.* The Administrator will grant provisional approval according to the procedure in paragraph (a)(3) of this section and will issue a written notice of approval or disapproval according to the procedures in paragraphs (a)(4) and (a)(5) of this section, the period for provisional certification shall not exceed 60 days following receipt of the complete recertification application by the Administrator, because the Administrator will issue a written notice of approval or disapproval within 60 days of receipt.

(c) *Certification procedures.* Prior to the deadline in § 75.4 of this part, the owner or operator shall conduct certification tests and in accordance with § 75.63, the designated representative shall submit an application to demonstrate that the continuous emission or opacity monitoring system and components meet the specifications in appendix A to this part. The owner or operator shall compare reference method values with output from the automated data acquisition and handling system that is part of the continuous emission monitoring system being tested. Except as specified in paragraphs (d) and (e) of this section, the owner or operator shall perform the following tests for certification or recertification of continuous emission or opacity monitoring systems or components according to the requirements of appendix A to this part:

(1) For each SO_2 pollutant concentration monitor and NO_x continuous emission monitoring system:

(i) A 7-day calibration error test, where, for the NO_x continuous emission monitoring system, this test is performed separately on the NO_x pollutant concentration monitor and the diluent gas monitor;

(ii) A linearity check, where, for the NO_x continuous emission monitoring system, this check is performed separately on the NO_x pollutant concentration monitor and the diluent gas monitor;

(iii) A relative accuracy test audit;

(iv) A bias test; and

(v) A cycle time/response time test.

(2) For each flow monitor:

(i) A 7-day calibration error test;

(ii) Relative accuracy test audits at three flue gas velocities;

(iii) A bias test (at normal operating load); and

(3) The relative accuracy test audits for the SO_2 pollution concentration monitor and the flow monitor shall be performed contemporaneously.

(4) A CO_2 diluent gas monitor certified for use in a NO_x continuous emission monitoring system shall be deemed certified for the purposes of § 75.10(a)(3).

(5) For each CO_2 pollutant concentration monitor which is not certified as part of a NO_x continuous emission monitoring system and for each SO_2-diluent continuous emission monitoring system:

(i) A 7-day calibration error test, where, for the SO_2-diluent system, this test is performed separately on each component monitor;

(ii) A linearity check, where, for the SO_2 diluent system, this check is performed separately on each component monitor;

(iii) A relatively accuracy test audit; and

(6) The owner or operator shall ensure that certification or recertification of a continuous opacity monitor for use under the Acid Rain Program is conducted according to one of the following procedures:

(i) Performance of the following tests for certification or recertification, according to the requirements of Performance Specification 1 in appendix B to part 60 of this chapter.

(ii) A continuous opacity monitoring system tested and certified previously under State or other federal requirements to meet the requirements of Performance Specification 1 shall be deemed certified for the purposes of this part.

(7) For the automated data acquisition and handling system, tests designed to verify:

(i) Proper computation of hourly averages for pollutant concentrations, flow rate, pollutant emission rates, and pollutant mass emissions; and

(ii) Proper computation and application of the missing data substitution procedures in subpart D of this part and the bias adjustment factors in Section 7 of appendix A to this part.

(8) When the optional SO_2 mass emissions estimation procedure in appendix D to this part or the optional NO_x emissions estimation protocol in appendix E of this part is used, the owner or operator shall provide data from a calibration test for each fuel flowmeter according to the appropriate calibration procedures among the following ASME methods: ASME MFC-

3M–1989 with September 1990 Errata, "Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi", ASME MFC–4M–1986 (Reaffirmed 1990) "Measurement of Gas Flow by Turbine Meters", ASME MFC–5M–1985 "Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters", ASME MFC–6M–1987 with June 1987 Errata, "Measurement of Fluid Flow in Pipes Using Vortex Flow Meters", ASME MFC–7M–1987 (Reaffirmed 1992), "Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles", or ASME MFC–9M–1988 with December 1989 Errata, "Measurement of Liquid Flow in Closed Conduits by Weighing Method", as required by appendices D and E of this part (all methods incorporated by reference under § 75.6 of this part).

(9) The owner or operator shall provide, or cause to be provided, adequate facilities for certification or recertification testing that include:

(i) Sampling ports adequate for test methods applicable to such facility, including:

(A) Volumetric flow rates, pollutant concentration, and pollutant emission rates can be accurately determined by applicable test methods and procedures; and

(B) A stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(ii) Basic facilities (i.e. electricity) for sampling and testing equipment.

(d) *Certification/recertification procedures for optional backup or portable continuous emission monitoring systems.* The owner or operator of an optional backup or an optional portable continuous emission monitoring system shall comply with all the requirements for initial certification and recertification according to the procedures specified in paragraphs (a) and (c) of this section for each backup or portable continuous emission monitoring system, except as follows: the owner or operator of a backup or portable continuous emission monitoring system may omit the 7-day calibration error test for certification or recertification of an SO_2 pollutant concentration monitor, flow monitor, NO_x pollutant concentration monitor, or diluent gas monitor, provided the backup or portable system is not used for reporting on affected unit(s) for more than 720 hours in any calendar year. Prior to each use for recording and reporting emissions, the owner or operator shall ensure that the certified backup or portable continuous emission monitoring system passes a linearity check (for pollutant concentration monitors) or a calibration error test (for flow monitors). The owner or operator shall comply with all the requirements for recertification of the backup or portable continuous emission monitoring system according to the procedures specified in paragraph (b) of this section (except that the 7-day calibration error test may be omitted) once every other year. However, when a backup or portable system is used for reporting more than 720 hours in one calendar year, it becomes a primary continuous emission monitoring system; then the owner or operator must ensure that the monitor or continuous emission monitoring system, previously considered as backup or portable, has passed all required certification tests, including the 7-day calibration error test, before valid data may be reported for more than 720 hours from any affected unit in a calendar year. Nevertheless, a portable monitor that qualifies as a reference monitor pursuant to the requirements of 40 CFR part 60, appendix A, need not be recertified prior to its use pursuant to paragraph (d) of this section.

(e) *Certification/recertification procedures for either peaking unit or by-pass stack/duct continuous emission monitoring systems.* The owner or operator of either a peaking unit or by-pass stack/duct continuous emission monitoring system shall comply with all the requirements for certification or recertification according to the procedures specified in paragraphs (a), (b), and (c) of this section, except as follows: the owner or operator need only perform one Nine-run relative accuracy test audit for certification or recertification of a flow monitor installed on the by-pass stack/duct or on the stack/duct used only by affected peaking unit(s). The relative accuracy test audit shall be performed during normal operation of the peaking unit(s) or the by-pass stack/duct.

(f) *Certification/recertification procedures for alternative monitoring systems.* The designated representative representing the owner or operator of each alternative monitoring system approved by the Administrator as equivalent to or better than a continuous emission monitoring system according to the criteria in subpart E of this part shall apply for certification to the Administrator prior to use of the system under the Acid Rain Program, and shall apply for recertification to the Administrator following a replacement, modification, or change according to the procedures in paragraph (c) of this section. The owner or operator of an alternative monitoring system shall comply with the notification and application requirements for certification or recertification according to the procedures specified in paragraphs (a) and (b) of this section.

(1) The Administrator will publish each request for initial certification of an alternative monitoring system in the **Federal Register** and, following a public comment period of 60 days, will issue a notice of approval or disapproval.

(2) No alternative monitoring system shall be authorized by the Administrator in a permit issued pursuant to part 72 of this chapter unless approved by the Administrator in accordance with this part.

(g) *Certification procedures for approved exceptions to CEMS.* The owner or operator of a gas-fired unit, oil-fired unit, or diesel-fired unit shall ensure that any measurement method used in lieu of a CEMS meets the general operating requirements of this part and of appendices D and E to this part, and the designated representative shall submit a certification application by the deadlines specified in § 75.4 of this part and prior to use in the Acid Rain Program.

§ 75.21 Quality assurance and quality control requirements.

(a) *Continuous emission monitoring systems.* The owner or operator of an affected unit shall operate, calibrate, and maintain each continuous emission monitoring system used under the Acid Rain Program according to the quality assurance and quality control procedures in appendix B of this part.

(b) *Continuous opacity monitoring systems.* The owner or operator of an affected unit shall operate, calibrate, and maintain each continuous opacity monitoring system used under the Acid Rain Program according to the procedures specified for State Implementation Plans, pursuant to part 51, appendix M of this chapter.

(c) *Calibration gases.* The owner or operator shall ensure that all calibration gases used to quality assure the operation of the instrumentation required by this part shall meet the definition in § 72.2 of this chapter.

§ 75.22 Reference test methods.

(a) The owner or operator shall use the following methods included in appendix A to part 60 of this chapter to conduct monitoring system tests for certification or recertification of continuous emission monitoring systems and quality assurance and quality control procedures.

(1) Methods 1, or 1A are the reference methods for selection of sampling site and sample traverses.

(2) Methods 2, 2A, 2C, or 2D are the reference methods for determination of volumetric flow.

(3) Methods 3, 3A, or 3B are the reference methods for the determination of the dry molecular weight O_2 and CO_2 concentrations in the emissions.

(4) Method 4 is the reference method for the determination of moisture in the stack.

(5) Methods 6, 6A, 6B or 6C, and 7, 7A, 7C, 7D or 7E, as applicable, are the reference methods for determining SO_2 and NO_x pollutant concentrations. (Methods 6A and 6B may also be used to determine SO_2 emission rate in lb/mmBtu.)

(6) Method 20 is the reference method for determining NO_x and diluent emissions from stationary gas turbines.

§ 75.23 Alternatives to ASTM methods.

(a) The designated representative of a unit may petition the Administrator for an alternative to any ASTM method prescribed in this part.

(b) The designated representative shall include the following information in the petition for use of an alternative method:

(1) A description of why the prescribed ASTM method is not being used or cannot be used;

(2) A description and diagram(s) of all equipment and procedures in the proposed alternative method;

(3) Data demonstrating that the proposed alternative method produces data of equal or greater precision and accuracy to that from the prescribed ASTM method(s).

§ 75.24 Out-of-control periods.

(a) If an out-of-control period occurs to a monitor or continuous emission monitoring system, the owner or operator shall take corrective action and repeat the tests applicable to the "out-of-control parameter" as described in appendix B of this part.

(1) For daily calibration error tests, an out-of-control period occurs when the calibration error of a pollutant concentration monitor exceeds 5.0 percent based upon the span value, the calibration error of a diluent gas monitor exceeds 1.0 percent O_2 or CO_2, or the calibration error of a flow monitor exceeds 6.0 percent based upon the span value, which is twice the applicable specification in Appendix A to this part.

(2) For quarterly linearity checks, an out-of-control period occurs when the error in linearity at any of three gas concentrations (low, mid-range, and high) exceeds the applicable specification in appendix A to this part.

(3) For relative accuracy test audits, an out-of-control period occurs when the relative accuracy exceeds the applicable specification in Appendix A to this part.

(b) When a monitor or continuous emission monitoring system is out-of-control, any data recorded by the monitor or monitoring system are not quality-assured and shall not be used in calculating monitor data availabilities pursuant to § 75.32 of this part.

(c) When a monitor or continuous emission monitoring system is out-of-control, the owner or operator shall take one of the following actions until the monitor or monitoring system has successfully met the relevant criteria in appendices A and B of this part as demonstrated by subsequent tests:

(1) Apply the procedures for missing data substitution to emissions from affected unit(s); or

(2) Use a certified backup or certified portable monitor or monitoring system or a reference method for measuring and recording emissions from the affected unit(s); or

(3) Adjust the gas discharge paths from the affected unit(s) with emissions normally observed by the out-of-control monitor or monitoring system so that all exhaust gases are monitored by a certified monitor or monitoring system meeting the requirements of appendices A and B of this part.

(d) When the bias test indicates a monitor or monitoring system is biased low (i.e., the arithmetic mean of the differences between the reference method value and the monitor or monitoring system measurements in a relative accuracy test audit exceed the bias statistic in section 7 of appendix A to this part), the owner or operator shall adjust the monitor or continuous emission monitoring system to eliminate the cause of bias such that it passes the bias test or calculate and use the bias adjustment factor as specified in section 2.3.3 of appendix B to this part and in accordance with § 75.7.

(e) The owner or operator shall determine if a continuous opacity monitoring system is out-of-control and shall take appropriate corrective actions according to the procedures specified for State Implementation Plans, pursuant to 40 CFR part 51, appendix M. When repeated out-of-control periods occur to a continuous opacity monitoring system, causing the monitor data availability of the system to fall below 90.0 percent, the owner or operator shall either:

(1) Use a certified backup continuous opacity monitoring system for measuring and recording opacity from the affected unit(s); or

(2) Use the procedures in Method 9 in appendix A to part 60 of this chapter to measure the opacity of emissions discharged to the atmosphere from the affected unit(s).

Subpart D—Missing Data Substitution Procedures

§ 75.30 General provisions.

(a) Except as provided in § 75.34 of this subpart, the owner or operator shall provide substitute data for each affected unit according to the missing data procedures in this subpart whenever the unit combusts any fuel and:

(1) A valid hour of SO_2 concentration data (in ppm) has not been measured and recorded for an affected unit by a certified SO_2 pollutant concentration monitor, or by an approved alternative monitoring method under subpart E of this part; or

(2) A valid hour of flow data (in scfh) has not been measured and recorded for an affected unit from a certified flow monitor, or by an approved alternative monitoring system under subpart E of this part; or

(3) A valid hour of NO_x emission rate data (in lb/mmBtu) has not been measured and recorded for an affected unit by a certified NO_x continuous emission monitoring system, or by an approved alternative monitoring system under subpart E of this part.

(b) However, the owner or operator shall have no need to provide substitute data according to the missing data procedures in this subpart if the owner or operator uses SO_2 concentration, flow, or NO_x emission rate data recorded from a certified backup or certified portable continuous emission monitor or a reference method when the certified primary monitor is down or out-of-control, provided that the backup or portable monitor has been certified according to the procedures in § 75.20 of this part prior to the missing data period, and provided that the backup or portable monitor passes a linearity check (for pollutant concentration monitors) or a calibration error test (for flow monitors) prior to each period of use of the certified backup monitor or certified portable monitor for recording and reporting emissions. Such use of certified portable monitor, certified backup monitor, or reference method is optional and at the discretion of the owner or operator.

(c) When the certified primary monitor is down or out-of-control, then data recorded for an affected unit from a certified backup or certified portable continuous emission monitor are used, as if such data were from the certified primary monitor, to calculate monitor data availability in § 75.32, and to provide the quality-assured data used in

the missing data procedures in §§ 75.31 and 75.33, such as the "hour after" value.

§ 75.31 Initial missing data procedures.

(a) During the first 720 quality-assured monitor operating hours following initial certification (i.e., beginning from the date and time of completion of successful certification tests), of the SO_2 pollutant concentration monitor and during the first 2,160 quality-assured monitor operating hours following initial certification of the flow monitor and NO_x continuous emission monitoring system(s), the owner or operator shall provide substitute data required under this subpart according to the procedures in paragraphs (b) and (c) of this section.

(b) *SO_2 concentration data.* For each hour of missing SO_2 concentration data, the owner or operator shall calculate the substitute data as follows:

(1) Whenever prior quality assured data exist, the owner or operator shall substitute, by means of the data acquisition and handling system, the average of the hourly SO_2 concentrations recorded for an affected unit by a certified monitor for the unit operating hour immediately before and the unit operating hour immediately after the missing data period for each hour of missing data (henceforth referred to as "the hour before and after").

(2) Whenever no prior quality-assured SO_2 concentration data exist, the owner or operator shall substitute the maximum potential concentration for SO_2, as specified in section 2.1 of appendix A, for each hour of missing data.

(c) *Volumetric flow and NO_x emission rate data.* For each hour of missing volumetric flow or NO_x emission rate data;

(1) Whenever prior quality-assured data exist in the load range corresponding to the operating load at the time the missing data period occurred, the owner or operator shall substitute, by means of the automated data acquisition and handling system, the average hourly flow rate (or NO_x emission rate) recorded for the affected unit by a certified flow monitor (or a certified NO_x continuous emission monitoring system). The flow rate (or NO_x emission rate) shall be calculated from the corresponding load range as determined using the procedure in appendix C of this part.

(2) Whenever no prior quality-assured flow or NO_x emission rate data exist for the corresponding load range, the owner and operator shall substitute the average hourly flow rate or the average hourly NO_x emission rate at the next higher level load range for which quality-assured data is available, for each hour of missing data.

(3) Whenever no prior quality-assured flow or NO_x emission rate data exist for any load range, the owner or operator shall use the maximum potential velocity to calculate and substitute the maximum flow rate or shall substitute the maximum potential NO_x emission rate, as specified in section 2.1 of appendix A, for each hour of missing data.

§ 75.32 Determination of monitor data availability for standard missing data procedures.

(a) Following initial certification, upon completion of the first 720 quality-assured monitor operating hours of the SO_2 pollutant concentration monitor or the first 2,160 quality-assured monitor operating hours of the flow monitor or NO_x continuous emission monitoring system, the owner or operator shall calculate and record, by means of the automated data acquisition and handling system, the percent monitor data availability for the SO_2 pollutant concentration monitor, the flow monitor, and the NO_x continuous emission monitoring system as follows:

(1) Prior to completion of 8,760 unit operating hours following initial certification, the owner or operator shall, for the purpose of applying the standard missing data procedures of § 75.33, use Equation 8 to calculate, hourly, percent monitor data availability.

$$\text{Percent monitor data availability} = \frac{\text{Total unit operating hours for which quality-assured data were recorded since certification}}{\text{Total unit operating hours since certification}} \times 100 \quad \text{(Eq. 8)}$$

$$\text{Percent monitor data availability} = \frac{\text{Total unit operating hours for which quality-assured data were recorded during previous 8,760 unit operating hours}}{8{,}760} \times 100 \quad \text{(Eq. 9)}$$

(2) Upon completion of 8,760 unit operating hours following initial certification and thereafter, the owner or operator shall, for the purpose of applying the standard missing data procedures of § 75.33, use Equation 9 to calculate, hourly, percent monitor data availability.

(3) The owner or operator shall include all unit operating hours, and all monitor operating hours for which quality-assured data were recorded by a certified primary monitor, a certified backup monitor, a certified portable monitor, and a reference method for that unit, and from an approved alternative monitoring system under subpart E of this part when calculating percent monitor data availability using Equation 8 or 9.

(b) Although the monitor data availability need not be recorded during the missing data period, then the owner or operator shall record the percent monitor data availability at the end of each missing data period, (and thereafter, continue to record monitor data availability hourly, pursuant to § 75.50).

§ 75.33 Standard missing data procedures.

(a) Following initial certification and upon completion of the first 720 quality-assured monitor operating hours of the SO_2 pollutant concentration monitor or the first 2,160 quality-assured monitor operating hours of the flow monitor or NO_x continuous emission monitoring

system, the owner or operator shall provide substitute data required under this subpart according to the procedures in paragraphs (b) and (c) of this section and depicted in Table 1 (SO_2) and Table 2 (NO_x, flow).

TABLE 1.—MISSING DATA PROCEDURE FOR SO_2 CEMS

Trigger conditions		Calculation routines	
Availability (percent)	Duration (N) of outage (hours)	Method	Lookback period
95 or more	N≤24	Average	HB/HA.
	N>24	Max. of average	HB/HA.
		Max. of 90th percentile	720 operating hours*.
90 or more, but below 95	N≤8	Average	HB/HA.
	N>8	Max. of average	HB/HA.
		Max. of 95th percentile	720 operating hours*.
Below 90	N >0	Maximum value [1]	720 operating hours*.

HB/HA=hour before and hour after the outage.
*=Quality-assured, monitor operating hours.
[1] Where unit with add-on emission controls can demonstrate that the controls are operating properly, as provided in §75.34, the unit may, upon approval, use the maximum controlled emission rate from the previous 720 operating hours.

TABLE 2.—MISSING DATA PROCEDURE FOR NO_x AND FLOW CEMS

Trigger conditions		Calculation routines		
Availability (percent)	Duration (N) of outage (hours)	Method	Lookback period	Load ranges
95 or more	N ≤ 24	Average	2160 operating hours*	Yes.
	N > 24	Max of average	HB/HA	No.
		Max of 90th percentile	2160 operating hours*	Yes.
90 or more, but below 95	N ≤ 8	Average	2160 operating hours*	Yes.
	N > 8	Max of Average	HB/HA	No.
		Max of 95th percentile	2160 operating hours*	Yes.
Below 90	N > 0	Maximum Value[1]	2160 operating hours*	Yes.

HB/HA = hour before and hour after the outage.
* = Quality-assured, monitor operating hours.
Where unit with add-on emission controls can demonstrate that the controls are operating properly, as provided in §75.34, the unit may, upon approval, use the maximum controlled emission rate from the previous 720 operating hours.

(b) *SO_2 concentration data.* For each hour of missing SO_2 concentration data,

(1) Whenever the monitor data availability is equal to or greater than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

(i) For a missing data period less than or equal to 24 hours, substitute the average of the hourly SO_2 concentrations recorded by an SO_2 pollutant concentration monitor for the hour before and the hour after the missing data period.

(ii) For a missing data period greater than 24 hours, substitute the greater of:

(A) The 90th percentile hourly SO_2 concentration recorded by an SO_2 pollutant concentration monitor during the previous 720 quality-assured monitor operating hours; or

(B) The average of the hourly SO_2 concentrations recorded by an SO_2 pollutant concentration monitor for the hour before and the hour after the missing data period.

(2) Whenever the monitor data availability is at least 90.0 percent but less than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

(i) For a missing data period of less than or equal to 8 hours, substitute the average of the hourly SO_2 concentrations recorded by an SO_2 pollutant concentration monitor for the hour before and the hour after the missing data period.

(ii) For a missing data period of more than 8 hours, substitute the greater of:

(A) the 95th percentile hourly SO_2 concentration recorded by an SO_2 pollutant concentration monitor during the previous 720 quality-assured monitor operating hours; or

(B) The average of the hourly SO_2 concentrations recorded by an SO_2 pollutant concentration monitor for the hour before and the hour after the missing data period.

(3) Whenever the monitor data availability is less than 90.0 percent, the owner or operator shall substitute for each hour of each missing data period the maximum hourly SO_2 concentration recorded by an SO_2 pollutant concentration monitor during the previous 720 quality-assured monitor operating hours.

(c) *Volumetric flow and NO_x emission rate data.* For each hour of missing volumetric flow or NO_x emission rate data,

(1) Whenever the monitor or continuous emission monitoring system data availability is equal to or greater than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

(i) For a missing data period less than or equal to 24 hours, substitute the average hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range recorded for each missing hour, as determined using the procedure in Appendix C to this part.

(ii) For a missing data period greater than 24 hours, substitute the greater of:

(A) The 90th percentile hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system at the corresponding

unit load range recorded for each missing hour during the previous 2,160 quality-assured monitor operating hours, as determined using the procedure in appendix C to this part; or

(B) The average of the hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system for the hour before and the hour after the missing data period.

(2) Whenever the monitor or continuous emission monitoring system data availability is at least 90.0 percent but less than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

(i) For a missing data period of less than or equal to 8 hours, substitute the average hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system at the corresponding unit load range recorded for the missing hour during the previous 2,160 quality-assured monitor operating hours, as determined using the procedure in appendix C to this part.

(ii) For a missing data period greater than 8 hours, substitute the greater of:

(A) The 95th percentile hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system at the corresponding unit load range recorded for the missing hour during the previous 2,160 quality-assured monitor operating hours, as determined using the procedure in appendix C to this part; or

(B) The average of the hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system for the hour before and the hour after the missing data period.

(2) Whenever the monitor or continuous emission monitoring system data availability is at least 90.0 percent but less than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

(i) For a missing data period of less than or equal to 8 hours, substitute the average hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system at the corresponding unit load range recorded for the missing hour during the previous 2,160 quality-assured monitor operating hours, as determined using the procedure in appendix C to this part.

(ii) For a missing data period greater than 8 hours, substitute the greater of:

(A) The 95th percentile hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system at the corresponding unit load range recorded for the missing hour during the previous 2,160 quality-assured monitor operating hours, as determined using the procedure in appendix C to this part; or

(B) The average of the hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system for the hour before and the hour after the missing data period.

(3) Whenever the monitor data availability is less than 90.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period by substituting the maximum hourly flow or NO_x emission rate recorded by the flow monitor or NO_x continuous emission monitoring system at the corresponding unit load range recorded for the missing hour during the previous 2,160 quality-assured monitor operating hours, as determined using the procedure in Section 2 of Appendix C to this part.

(4) Whenever no prior quality-assured flow or NO_x emission rate data exist for the corresponding load range, the owner or operator shall substitute the maximum hourly flow rate or the maximum hourly NO_x emission rate at the next higher level load range for which quality-assured data is available for each hour of missing data.

§ 75.34 Units with add-on emission controls.

(a) The owner or operator of an affected unit equipped with add-on SO_2 and/or NO_x emission controls may choose one of the following options:

(1) The owner or operator may use the missing data routine as specified for all affected units in §§ 75.31 through 75.33. In addition, the owner or operator may petition the Administrator to replace the maximum recorded value in the last 720 quality-assured monitor operating hours with a value corresponding to the maximum controlled emission rate (an emission rate recorded when the add-on emission controls were operating) recorded during the last 720 quality-assured monitor operating hours. The owner or operator must demonstrate that the following conditions are met: the monitor data availability, calculated in accordance with § 75.32, for the affected unit is below 90 percent and parametric monitors can establish that the add-on emission controls were operating properly during the time period under petition.

(2) The owner or operator may petition the Administrator under § 75.66 for approval of site-specific parametric monitoring procedure(s) for calculating substitute data for missing SO_2 pollutant concentration and NO_x emission rate data in accordance with the requirements of this section and of appendix C to this part.

(b) For an affected unit equipped with add-on SO_2 emission controls, the owner or operator may petition the Administrator to approve a parametric monitoring procedure, as described in appendix C of this part, for calculating substitute SO_2 concentration data for missing data periods. The owner or operator shall use the procedures in § 75.31, 75.33, or § 75.34(a) of this part for providing substitute data for missing SO_2 concentration data unless a parametric monitoring procedure has been approved by the Administrator.

(1) Where the monitoring data availability is 90.0 percent or more for an outlet SO_2 pollutant concentration monitor, the owner or operator may calculate substitute data using an approved parametric monitoring procedure.

(2) Where the monitor data availability for an outlet SO_2 pollutant concentration monitor is less than 90.0 percent, the owner or operator shall calculate substitute data using the procedures in § 75.33(b)(3) or § 75.34(a) of this part, even if the Administrator has approved a parametric monitoring procedure.

(c) For an affected unit with NO_x add-on emission controls, the owner or operator may petition the Administrator to approve a parametric monitoring procedure, as described in Appendix C of this part, in order to calculate substitute NO_x emission rate data for missing data periods. The owner or operator shall use the procedures in §§ 75.31 or 75.33 of this part for providing substitute data for missing NO_x emission rate data prior to receiving the Administrator's approval for a parametric monitoring procedure.

(1) Where monitor data availability for a NO_x continuous emission monitoring system is 90.0 percent or more, the owner or operator may calculate substitute data using an approved parametric monitoring procedure.

(2) Where monitor data availability for a NO_x continuous emission monitoring system is less than 90.0 percent, the owner or operator shall calculate substitute data using the procedure in § 75.33(c)(3) or petition in accordance with § 75.34(a)(1) of this part, even if the

Administrator has approved a parametric monitoring procedure.

(d) The owner or operator shall provide information as described in subparts F and G of this part to verify the proper operation of the SO_2 or NO_x emission controls during all periods of missing data. Whenever such data are not provided or proper operation of the SO_2 or NO_x emission controls has not been maintained, the owner or operator shall substitute the maximum potential concentration for NO_x, as defined in section 2.1 of Appendix A, and the minimum O_2 concentration or maximum O_2 concentration used to determine the maximum potential concentration of SO_2 in section 2.1.1.1 of appendix A in calculations of NO_x emission rate or the maximum hourly SO_2 concentration recorded by the inlet monitor during the previous 720 quality assured monitor operating hours for each hour of missing data until parametric data demonstrating proper operation of the SO_2 or NO_x emission controls are available.

Subpart E—Alternative Monitoring Systems

§ 75.40 General demonstration requirements.

(a) The owner or operator of an affected unit, or the owner or operator of an affected unit and representing a class of affected units which meet the criteria specified in § 75.47, required to install a continuous emission monitoring system may apply to the Administrator for approval of an alternative monitoring system (or system component) to determine average hourly emission data for SO_2, NO_x, and/or volumetric flow by demonstrating that the alternative monitoring system has the same or better precision, reliability, accessibility, and timeliness as that provided by the continuous emission monitoring system.

(b) The requirements of this subpart shall be met by the alternative monitoring system when compared to a contemporaneously operating, fully certified continuous emission monitoring system or a contemporaneously operating reference method, where the appropriate reference methods are listed in § 75.22.

§ 75.41 Precision criteria.

(a) *Data collection and analysis.* To demonstrate precision equal to or better than the continuous emission monitoring system, the owner or operator shall conduct an F-test, a correlation analysis, and a t-test for bias as described in this section. The t-test shall be performed only on sample data at the normal operating level and primary fuel supply, whereas the F-test and the correlation analysis must be performed on each of the data sets required under paragraphs (a)(4) and (a)(5) of this section. The owner or operator shall collect and analyze data according to the following requirements:

(1) Data from the alternative monitoring system and the continuous emission monitoring system shall be collected and paired in a manner that ensures each pair of values applies to hourly average emissions during the same hour.

(2) An alternative monitoring system that directly measures emissions shall have probes or other measuring devices in locations that are in proximity to the continuous emission monitoring system and shall provide data on the same parameters as those measured by the continuous emission monitoring system. Data from the alternative monitoring system shall meet the statistical tests for precision in paragraph (c) of this section and the t-test for bias in appendix A of this part.

(3) An alternative monitoring system that indirectly quantifies emission values by measuring inputs, operating characteristics, or outputs and then applying a regression or another quantitative technique to estimate emissions, shall meet the statistical tests for precision in paragraph (c) of this section and the t-test for bias in Appendix A of this part.

(4) For flow monitor alternatives, the alternative monitoring system must provide sample data for each of three different exhaust gas velocities while the unit or units, if more than one unit exhausts into the stack or duct, is burning its primary fuel at:

(i) A frequently used low operating level, selected within the range between the minimum safe and stable operating level and 50 percent of the maximum operating level,

(ii) A frequently used high operating level, selected within the range between 80 percent of the maximum operating level and the maximum operating level, and

(iii) The normal operating level, or an evenly spaced intermediary level between low and high levels used if the normal operating level is within a specified range, (10.0 percent of the maximum operating level) of either (a)(4) (i) or (ii) of this section.

(5) For pollutant concentration monitor alternatives, the alternative monitoring system shall provide sample data for the primary fuel supply and for all alternative fuel supplies that have significantly different sulfur content.

(6) For the normal unit operating level and primary fuel supply, paired hourly sample data shall be provided for at least 90.0 percent of the hours during 720 unit operating hours. For each of the remaining two operating levels for flow monitor alternatives, and for each alternative fuel supply for pollutant concentration monitor alternatives, paired hourly sample data shall be provided for at least 24 successive unit operating hours.

(7) The owner or operator shall not use missing data substitution procedures to provide sample data.

(8) If the collected data meet the requirements of the F-test, the correlation test, and the t-test at one or more, but not all, of the operating levels or fuel supplies, the owner or operator may elect to continue collecting the paired data for up to 1,440 additional operating hours and repeat the statistical tests using the data for the entire 30- to 90-day period.

(9) The owner or operator shall provide two separate time series data plots for the data at each operating level or fuel supply described in paragraphs (a)(4) and (a)(5) of this section. Each data plot shall have a horizontal axis that represents the clock hour and calendar date of the readings and shall contain a separate data point for every hour for the duration of the performance evaluation. The data plots shall show the following:

(i) Percentage difference versus time where the vertical axis represents the percentage difference between each paired hourly reading generated by the continuous emission monitoring system and the alternative emission monitoring system as calculated using the following equation:

$$\Delta e = \frac{e_p - e_v}{e_v} \times 100\%$$

(Eq.10)

where,

Δe=Percentage difference between the readings generated by the alternative monitoring system and the continuous emission monitoring system.

e_p=Measured value from the alternative monitoring system.

e_v=Measured value from the continuous emission monitoring system.

(ii) Alternative monitoring system readings and continuous emissions monitoring system readings versus time where the vertical axis represents

hourly pollutant concentrations or volumetric flow, as appropriate, and two different symbols are used to represent the readings from the alternative monitoring system and the continuous emission monitoring system, respectively.

(b) *Data screening and calculation adjustments.* In preparation for conducting the statistical tests, described in paragraph (c) of this section, the owner or operator may screen the data for lognormality and time dependency autocorrelation. If either is detected, the owner or operator shall make the following calculation adjustments:

(1) *Lognormality.* The owner or operator shall conduct any screening and adjustment for lognormality according to the following procedures.

(i) Apply the log transformation to each measured value of either the certified continuous emissions monitoring system or certified flow monitor, using the following equation:

$l_v = \ln e_v$

where,

e_v=Hourly value generated by the certified continuous emissions monitoring system or certified flow monitoring system

l_v=Hourly lognormalized data values for the certified monitoring system

and to each measured value, e_p, of the proposed alternative monitoring system, using the following equation to obtain the lognormalized data values, l_p:

$l_p = \ln e_p$

where,

e_p=Hourly value generated by the proposed alternative monitoring system.

l_p=Hourly lognormalized data values for the proposed alternative monitoring system.

(ii) Separately test each set of transformed data, l_v and l_p, for normality, using the following:

(A) Shapiro-Wilk test;

(B) Histogram of the transformed data; and

(C) Quantile-Quantile plot of the transformed data.

(iii) The transformed data in a data set will be considered normally distributed if all of the following conditions are satisfied:

(A) The Shapiro-Wilk test statistic, W, is greater than or equal to 0.75 or is not statistically significant at α=0.05.

(B) The histogram of the data is unimodal and symmetric.

(C) The Quantile-Quantile plot is a diagonal straight line.

(iv) If both of the transformed data sets, l_v and l_p, meet the conditions for normality, specified in paragraphs (b)(1)(iii) (A) through (C) of this section, the owner or operator may use the transformed data, l_v and l_p, in place of the original measured data values in the statistical tests for alternative monitoring systems as described in paragraph (c) of this section and in appendix A of this part.

(v) If the transformed data are used in the statistical tests in paragraph (c) of this section and in appendix A of this part, the owner or operator shall provide the following:

(A) Copy of the original measured values and the corresponding transformed data in printed and electronic format.

(B) Printed copy of the test results and plots described in paragraphs (b)(1) (i) through (iii) of this section.

(2) *Time dependency (autocorrelation).* The screening and adjustment for time dependency are conducted according to the following procedures:

(i) Calculate the degree of autocorrelation of the data on their LAG1 values, where the degree of autocorrelation is represented by the Pearson autocorrelation coefficient, ρ, computed from an AR(1) autoregression model, such that where,

$$\rho = \frac{COV(x_i', x_i'')}{S_{x_i'} S_{x_i''}}$$

(Eq. 13)

X'_i=The original data value at i.

X''_i=The LAG1 data value at hour i.

$COV(X'_i, X''_i)$=The autocovariance of X'_i and defined by,

$$COV(x_i', x_i'') = \frac{\sum_{i=1}^{n} (x_i' - \bar{x}')(x_i'' - \bar{x}'')}{(n-1)}$$

(Eq. 14)

n=The total number of observations in which both the original value, X'_i, and the lagged value, X''_i, are available in the data set.

S'_{x_i}=The standard deviation of the original data values, X'_i defined by,

$$S_{x_i'} = \sqrt{\frac{\sum_{i=1}^{n} (x_i' - \bar{x}')^2}{n-1}}$$

(Eq. 15)

S''_{x_i}=The standard deviation of the LAG1 data values, X''_i, defined by

$$S_{x_i''} = \sqrt{\frac{\sum_{i=1}^{n} (x_i'' - \bar{x}'')^2}{n-1}}$$

(Eq. 16)

$\bar{X}'$=The mean of the original data values, X'_i defined by

$$\bar{x}' = \frac{\sum_{i=1}^{n} x_i'}{n}$$

(Eq. 17)

$\bar{X}''$=The mean of the LAG1 data values, X''_i, defined by

$$\bar{x}'' = \frac{\sum_{i=1}^{n} x_i''}{n}$$

(Eq. 18)

(ii) The data in a data set will be considered autocorrelated if the autocorrelation coefficient, ρ, is significant at the 5 percent significance level. To determine if this condition is satisfied, calculate Z using the following equation:

$$Z = 0.5\left[\ln\left(\frac{1+\rho}{1-\rho}\right)\right]\sqrt{n-3}$$

(Eq. 19)

If $Z > 1.96$, then the autocorrelation coefficient, ρ, is significant at the 5 percent significance level ($\alpha = 0.05$).

(iii) If the data in a data set satisfy the conditions for autocorrelation, specified in paragraph (b)(2)(ii) of this section, the variance of the data, S^2, may be adjusted using the following equation:

$S^2_{adj} = VIF \times S^2$

(Eq. 20)

where,

S^2=The original, unadjusted variance of the data set.

VIF=The variance inflation factor, defined by

$$VIF = \frac{1}{\left[1 - \frac{2\rho}{(n-1)(1-\rho)} + \frac{2\rho(1-\rho^n)}{n(n-1)(1-\rho)^2}\right]}$$

(Eq. 21)

S^2_{adj}=The autocorrelation-adjusted variance for the data set.

(iv) The procedures described in paragraphs (b)(2)(i)–(iii) of this section may be separately applied to the following data sets in order to derive distinct autocorrelation coefficients and variance inflation factors for each data set:

(A) The set of measured hourly values, e_v, generated by the certified continuous emissions monitoring system or certified flow monitoring system.

(B) The set of hourly values, e_p, generated by the proposed alternative monitoring system,

(C) The set of hourly differences, $e_v - e_p$, between the hourly values, e_v, generated by the certified continuous emissions monitoring system or certified flow monitoring system and the hourly values, e_p, generated by the proposed alternative monitoring system.

(v) For any data set, listed in paragraph (b)(2)(iv) of this section, that satisfies the conditions for autocorrelation specified in paragraph (b)(2)(ii) of this section, the owner or operator may adjust the variance of that data set, using Equation 20 of this section.

(A) The adjusted variance may be used in place of the corresponding original variance in the F-test Equation 23 of this section.

(B) In place of the standard error of the mean,

$$\frac{S_d}{\sqrt{n}},$$

in the bias test Equation A–9 of Appendix A the following adjusted standard error of the mean may be used:

$$\left(\frac{S_d}{\sqrt{n}}\right)_{adj} = \left[\sqrt{\left(\frac{1+\rho}{1-\rho}\right) - \left(\frac{2\rho(1-\rho^n)}{n(1-\rho)^2}\right)}\right] \times \sqrt{VIF} \times \left(\frac{S_d}{\sqrt{n}}\right) \qquad \text{(Eq. 22)}$$

where,

$\left(\frac{S_d}{\sqrt{n}}\right)_{adj}$ = The autocorrelation-adjusted standard error of the mean.

(vi) For each data set in which a variance adjustment is used, the owner or operator shall provide the following:

(A) All values in the data set in printed and electronic format.

(B) Values of the autocorrelation coefficient, its level of significance, the variance inflation factor, and the unadjusted original and adjusted values found in Equations 20 and 22 of this section.

(C) Equation and related statistics of the AR(1) autoregression model of the data set.

(D) Printed documentation of the intermediate calculations used to derive the autocorrelation coefficient and the Variance Inflation Factor.

(c) *Statistical Tests.* The owner or operator shall perform the F-test and correlation analysis as described in this paragraph and the t-test for bias described in Appendix A of this part to demonstrate the precision of the alternative monitoring system.

(1) *F-test.* The owner or operator shall conduct the F-test according to the following procedures.

(i) Calculate the variance of the certified continuous emission monitoring system or certified flow monitor as applicable, S_v^2, and the proposed method, S_p^2, using the following equation.

$$S^2 = \frac{\sum_{i=1}^{n} (e_i - e_m)^2}{n-1} \qquad \text{(Eq. 23)}$$

where,

e_i = Measured values of either the certified continuous emission monitoring system or certified flow monitor, as applicable, or proposed method.

e_m = Mean of either the certified continuous emission monitoring system or certified flow monitor, as applicable, or proposed method values.

n = Total number of paired samples.

(ii) Determine if the variance of the proposed method is significantly different from that of the certified continuous emission monitoring system or certified flow monitor, as applicable, by calculating the F-value using the following equation.

$$F = \frac{S_p^2}{S_v^2} \qquad \text{(Eq. 24)}$$

Compare the experimental F-value with the critical value of F at the 95-percent confidence level with n-1 degrees of freedom. The critical value is obtained from a table for F-distribution. If the calculated F-value is greater than the critical value, the proposed method is unacceptable.

(2) *Correlation analysis.* The owner or operator shall conduct the correlation analysis according to the following procedures.

(i) Plot each of the paired emissions readings as a separate point on a graph where the vertical axis represents the value (pollutant concentration or volumetric flow, as appropriate) generated by the alternative monitoring system and the horizontal axis represents the value (pollutant concentration or volumetric flow, as appropriate) generated by the continuous emission monitoring system. On the graph, draw a horizontal line representing the mean value, e_p, for the

alternative monitoring system and a vertical line representing the mean value, e_v, for the continuous emission monitoring system where,

$$\overline{e_p} = \frac{\sum e_p}{n}$$

(Eq. 25)

$$\overline{e_v} = \frac{\sum e_v}{n}$$

(Eq. 26)

where,

e_p=Hourly value generated by the alternative monitoring system.

e_v=Hourly value generated by the continuous emission monitoring system.

n=Total number of hours for which data were generated for the tests.

A separate graph shall be produced for the data generated at each of the operating levels or fuel supplies described in paragraphs (a)(4) and (a)(5) of this section.

(ii) Use the following equation to calculate the coefficient of correlation, r, between the emissions data from the alternative monitoring system and the continuous emission monitoring system using all hourly data for which paired values were available from both monitoring systems.

$$r = \frac{\sum e_p e_v - (\sum e_p)(\sum e_v)/n}{\left(\sum e_p^2 - (\sum e_p)^2/n\right)\left[\sum e_p^2 - (\sum e_v)^2/n\right]^{1/2}}$$

(Eq. 27)

(Eq. 27)

(iii) If the calculated r-value is less than 0.8, the proposed method is unacceptable.

§ 75.42 Reliability criteria.

To demonstrate reliability equal to or better than the continuous emission monitoring system, the owner or operator shall demonstrate that the alternative monitoring system is capable of providing valid 1-hr averages for 95.0 percent or more of unit operating hours over a 1-yr period and that the system meets the applicable requirements of Appendix B of this part.

§ 75.43 Accessibility criteria.

To demonstrate accessibility equal to or better than the continuous emission monitoring system, the owner or operator shall provide reports and onsite records of emission data to demonstrate that the alternative monitoring system provides data meeting the requirements of subparts F and G of this part.

§ 75.44 Timeliness criteria.

To demonstrate timeliness equal to or better than the continuous emission monitoring system, the owner or operator shall demonstrate that the alternative monitoring system can meet the requirements of subparts F and G of this part; can provide a continuous, quality-assured, permanent record of certified emissions data on an hourly basis; and can issue a record of data for the previous day within 24 hours.

§ 75.45 Daily quality assurance criteria.

The owner or operator shall either demonstrate that daily tests equivalent to those specified in Appendix B of this part can be performed on the alternative monitoring system or demonstrate and document that such tests are unnecessary for providing quality-assured data.

§ 75.46 Missing data substitution criteria.

The owner or operator shall demonstrate that all missing data can be accounted for in a manner consistent with the applicable missing data procedures in subpart D of this part.

§ 75.47 Criteria for a class of affected units.

(a) The owner or operator of an affected unit may represent a class of affected units for the purpose of applying to the Administrator for a class-approved alternative monitoring system.

(b) The owner or operator of an affected unit representing a class of affected units shall provide the following information:

(1) A description of the affected unit and how it appropriately represents the class of affected units;

(2) A description of the class of affected units, including data describing all the affected units which will comprise the class; and

(3) A demonstration that the magnitude of emissions of all units which will comprise the class of affected units are *de minimis*.

(c) If the Administrator determines that the emissions from all affected units which will comprise the class of units are *de minimis*, then the Administrator shall publish notice in the **Federal Register**, providing a 30-day period for public comment, prior to granting a class-approved alternative monitoring system.

§ 75.48 Petition for an alternative monitoring system.

(a) The designated representative shall submit the following information in the application for certification or recertification of an alternative monitoring system.

(1) Source identification information.

(2) A description of the alternative monitoring system.

(3) Data, calculations, and results of the statistical tests, specified in § 75.41(c) of this part, including:

(i) Date and hour.

(ii) Hourly test data for the alternative monitoring system at each required operating level and fuel type.

(iii) Hourly test data for the continuous emissions monitoring system at each required operating level and fuel type.

(iv) Arithmetic mean of the alternative monitoring system measurement values, as specified in Equation 24 in § 75.41(c) of this part, of the continuous emission monitoring system values, as specified on Equation 25 in § 75.41(c) of this part, and of their differences.

(v) Standard deviation of the difference, as specified in Equation A–8 in Appendix A to this part.

(vi) Confidence coefficient, as specified in Equation A–9 in Appendix A to this part.

(vii) The bias test results as specified in § 7.6.4 in Appendix A to this part.

(viii) Variance of the measured values for the alternative monitoring system and of the measured values for the continuous emissions monitoring system, as specified in Equation 22 in § 75.41(c) of this part.

(ix) F-statistic, as specified in Equation 23 in § 75.41(c) of this part.

(x) Critical value of F at the 95-percent confidence level with n-1 degrees of freedom.

(xi) Coefficient of correlation, r, as specified in Equation 26 in § 75.41(c) of this part.

(4) Data plots, specified in §§ 75.41(a)(9) and 75.41(c)(2)(i) of this part.

(5) Results of monitor reliability analysis.

(6) Results of monitor accessibility analysis.

(7) Results of monitor timeliness analysis.

(8) A detailed description of the process used to collect data, including location and method of ensuring an accurate assessment of operating hourly conditions on a real-time basis.

(9) A detailed description of the operation, maintenance, and quality assurance procedures for the alternative monitoring system as required in Appendix B of this part.

(10) A description of methods used to calculate heat input or diluent gas concentration, if applicable.

(11) Results of tests and measurements (including the results of all reference method field test sheets, charts, laboratory analyses, example calculations, or other data as appropriate) necessary to substantiate that the alternative monitoring system is equivalent in performance to an appropriate, certified operating continuous emission monitoring system.

Subpart F—Recordkeeping Requirements

§ 75.50 General recordkeeping provisions.

(a) *Recordkeeping requirements for affected sources.* The owner or operator of any affected source subject to the requirements of this part shall maintain for each affected unit [or for each group of affected or nonaffected units utilizing a common stack and common monitoring systems pursuant to § 75.16–§ 75.18 of this part (referred to hereafter as "each affected unit")] a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. This file shall contain the following information:

(1) The data and information required in paragraphs (b) through (f) of this section;

(2) The component data and information used to calculate values required in paragraphs (b) through (f) of this section;

(3) The current monitoring plan as specified in § 75.53 of this part; and

(4) The quality control plan as described in Appendix B to this part.

(b) *Operating parameter record provisions.* The owner or operator shall record hourly the following information on unit operating time, heat input, and load for each affected unit, including individual affected units utilizing a common stack except as provided in paragraph (b)(6) of this section for gas-fired units.

(1) Date and hour;

(2) Unit operating time (rounded to nearest hour);

(3) Total integrated hourly gross unit load (rounded to nearest MW_{ge}) (or steam load in lb/hr at stated temperature and pressure, rounded to the nearest lb/hr, if elected in the monitoring plan);

(4) Operating load range corresponding to total integrated gross load of 1–10, except for units using a common stack, which may use the number of unit load ranges up to 20, specified in the monitoring plan for the common stack;

(5) Total heat input (mmBtu, rounded to the nearest tenth); and

(6) For gas-fired units, the owner or operator may record total heat input (mmBtu, rounded to the nearest tenth) daily.

(c) *SO_2 emission record provisions.* The owner or operator shall record hourly the information required by this paragraph for each affected unit or group of units using a common stack and common monitoring systems, except a gas-fired or oil-fired unit for which the owner or operator is using the optional protocol in Appendix D to this part for estimating SO_2 mass emissions:

(1) For SO_2 concentration, as measured and reported from the certified primary monitor, certified back-up or certified portable monitor, or other approved method of emissions determination:

(i) Monitor-channel identification code as provided for in § 75.53;

(ii) Date and hour;

(iii) Average hourly SO_2 concentration (ppm, rounded to the nearest tenth),

(iv) Average hourly SO_2 concentration (ppm, rounded to the nearest tenth) adjusted for bias, if bias adjustment factor is required as provided for in § 75.24(d) of this part;

(v) Percent monitor data availability (recorded to the nearest tenth of a percent) calculated pursuant to § 75.32 of this part; and

(vi) Method of determination for average hourly SO_2 concentration using Codes 1–12 in Table 3 of this section.

(2) For flow as measured and reported from the certified primary monitor, certified back-up or certified portable monitor or other approved method of emissions determination:

(i) Monitor-channel identification code as provided for in § 75.53;

(ii) Date and hour;

(iii) Average hourly volumetric flow rate (in scfh, rounded to the nearest thousand);

(iv) Average hourly volumetric flow rate (in scfh, rounded to the nearest thousand) adjusted for bias, if bias adjustment factor required as provided for in § 75.24(d) of this part;

(v) Average hourly moisture content of flue gases (volume fraction) where SO_2 concentration is measured on dry basis;

(vi) Percent monitor data availability, (recorded to the nearest tenth of a percent), calculated pursuant to § 75.32 of this part; and

(vii) Method of determination for average hourly flow rate using Codes 1–12 in Table 3.

(3) For SO_2 mass emissions as measured and reported from the certified primary monitoring system, certified back-up or certified portable monitoring systems, or other approved method of emissions determination:

(i) Date and hour;

(ii) Average hourly SO_2 mass emission (lb/hr, rounded to the nearest tenth);

(iii) Average hourly SO_2 mass emissions (lb/hr, rounded to the nearest tenth) adjusted for bias, if bias adjustment factor required, as provided for in § 75.24(d); and

(iv) Unique three-digit code identifying emissions formula used to derive hourly SO_2 mass emissions from SO_2 concentration and flow data in paragraphs (c)(1) and (c)(2) of this section as provided for in § 75.53.

TABLE 3.—CODES FOR METHOD OF EMISSIONS AND FLOW DETERMINATION

Code	Hourly emissions/flow measurement or estimation method
1	Certified primary emission/flow monitoring system.
2	Certified back-up or certified portable emission/flow monitoring system.
3	Approved alternative monitoring system.
4	Reference Method: SO_2: Method 6, 6A, 6B, or 6C. Flow: Method 2, 2A, 2C, or 2D. NO_x: Method 7, 7A, 7C, 7D, or 7E.
5	For units with add-on SO_2 and/or NO_x emission controls: SO_2 concentration or NO_x emission rate estimate from Agency preapproved parametric monitoring method.
6	Average of the hourly SO_2 concentrations, flow, or NO_x emission rate for the hour before and the hour following a missing data period.
7	Average hourly SO_2 concentration, flow rate, or NO_x emission rate using initial missing data procedures.
8	90th percentile hourly SO_2 concentration, flow rate, or NO_x emission rate.
9	95th percentile hourly SO_2 concentration, flow rate, or NO_x emission rate.
10	Maximum hourly SO_2 concentration, flow rate, or NO_x emission rate.
11	Average hourly flow rate or NO_x emission rate in corresponding load range.

TABLE 3.—CODES FOR METHOD OF EMISSIONS AND FLOW DETERMINATION—Continued

Code	Hourly emissions/flow measurement or estimation method
12	Maximum potential concentration of SO_2 maximum potential flow rate, or NO_x emission rate corresponding to maximum potential concentration of NO_x and minimum O_2 or maximum CO_2 concentration, as determined using section 2.1 of Appendix A of this part.
13	Other data (specify method).

(d) *NO_x emission record provisions.* The owner or operator shall record hourly the information required by this paragraph for each affected unit, except for a gas-fired peaking unit or oil-fired peaking unit for which the owner or operator is using the option protocol in Appendix E to this part for estimating NO_x emission rate. For each NO_x emission rate as measured and reported from the certified primary monitor, certified back-up or certified portable monitor, or other approved method of emissions determination:

(1) Monitor-channel identification code as provided for in § 75.53;

(2) Date and hour;

(3) Average hourly NO_x concentration (ppm, rounded to the nearest tenth);

(4) Average hourly diluent gas concentration (percent O_2 or percent CO_2, rounded to the nearest tenth);

(5) Average hourly NO_x emission rate (lb/mmBtu, rounded to nearest hundredth);

(6) Average hourly NO_x emission rate (lb/mmBtu, rounded to nearest hundredth) adjusted for bias, if bias adjustment factor is required as provided for in § 75.24(d) of this part;

(7) Percent monitoring system data availability, (recorded to the nearest tenth of a percent), calculated pursuant to § 75.32 of this part;

(8) Method of determination for average hourly NO_x emission rate using Codes 1–12 in Table 3; and

(9) Unique three-digit code identifying emissions formula used to derive average hourly NO_x emission rate, as provided for in § 75.53.

(e) *CO_2 emission record provisions.* The owner or operator shall record or calculate CO_2 emissions for each affected unit using one of the following methods specified in this section:

(1) If the owner or operator chooses to use a CO_2 continuous emission monitoring system (or an O_2 continuous emission monitor and flow monitor as specified in Appendix F), then the owner or operator shall record hourly the following information for CO_2 mass emissions, as measured and reported from the certified primary monitor, certified back-up or certified portable monitor, or other approved method of emissions determination:

(i) Monitor-channel identification code as provided for in § 75.53;

(ii) Date and hour;

(iii) Average hourly CO_2 (or O_2) concentration (in percent, rounded to the nearest tenth);

(iv) Average hourly volumetric flow rate (scfh, rounded to the nearest scf);

(v) Average hourly CO_2 mass emissions (tons/hr, rounded to the nearest tenth);

(vi) Percent monitor data availability (recorded to the nearest tenth of a percent); calculated pursuant to § 75.32 of this part;

(vii) Method of determination for average hourly CO_2 mass emissions using Codes 1–12 in Table 3; and

(viii) Unique three-digit emissions formula used to derive average hourly CO_2 mass emissions, as provided for in § 75.53.

(2) As an alternative to § 75.50(e)(1), the owner or operator may use the procedures in § 75.13 and in Appendix G to this part, and shall record daily the following information for CO_2 mass emissions:

(i) Date;

(ii) Average daily combustion-formed CO_2 mass emissions (tons/day, rounded to the nearest tenth);

(iii) For coal-fired units, flag indicating whether optional procedure to adjust combustion-formed CO_2 mass emissions for carbon retained in flyash has been used and, if so, the adjustment;

(iv) For a unit with a wet flue gas desulfurization system or other controls generating CO_2, average daily sorbent-related CO_2 mass emissions (tons/day, rounded to the nearest tenth); and

(v) For a unit with a wet flue gas desulfurization system or other controls generating CO_2, average total daily CO_2 mass emissions (tons/day, rounded to the nearest tenth) as sum of combustion-formed emissions and sorbent-related emissions.

(f) *Opacity record provisions.* The owner or operator shall record every six minutes (or other averaging period specified by the State or local air pollution control agency) the information required by this paragraph for each affected unit, except as provided for in § 75.14 (b), (c), and (d). The owner or operator shall also keep records of all incidents of opacity monitor downtime during unit operation, including reason(s) for the monitor outage(s) and any corrective action(s) taken for opacity, as measured and reported by the continuous opacity monitoring system:

(1) Monitor-channel identification code;

(2) Date, hour, and minute;

(3) Average opacity of emissions (in percent opacity);

(4) If the average opacity of emissions exceeds the applicable standard, then a code indicating such an exceedance has occurred; and

(5) Percent monitor data availability, recorded to the nearest tenth of a percent, calculated pursuant to § 75.32 of this part.

§ 75.51 General recordkeeping provisions for specific situations.

(a) *Specific SO_2 emission record provisions for units with qualifying Phase I technology.* In addition to the SO_2 emissions information required in § 75.50(c) of this part, from January 1, 1997, through December 31, 1999, the owner or operator shall record the applicable information in this paragraph for each affected unit on which SO_2 emission controls have been installed and operated for the purpose of meeting qualifying Phase I technology requirements pursuant to § 72.42 of this chapter and § 75.15.

(1) For units with post-combustion emission controls:

(i) Monitor-channel identification codes for each inlet and outlet SO_2-diluent continuous emission monitoring system;

(ii) Date and hour;

(iii) Average hourly inlet SO_2 emission rate (lb/mmBtu, rounded to nearest hundredth);

(iv) Average hourly inlet SO_2 concentration (ppm, rounded to the nearest tenth) adjusted for bias, if bias adjustment factor required (see § 75.24(d) of this part);

(v) Average hourly outlet SO_2 emission rate (lb/mmBtu, rounded to nearest hundredth);

(vi) Average hourly outlet SO_2 concentration (ppm, rounded to the nearest tenth) adjusted for bias, if bias adjustment factor required (see § 75.24(d) of this part);

(vii) Percent data availability for both inlet and outlet SO_2-diluent continuous emission monitoring systems (recorded to the nearest tenth of a percent), calculated pursuant to Equation 8 of § 75.32 (for the first 8,760 unit operating hours following initial certification) and Equation 9 of § 75.32, thereafter; and

(viii) Emissions formula used to derive average hourly SO_2 mass emissions for each affected unit or group of units using a common stack.

(2) For units with combustion and/or pre-combustion emission controls:

(i) Monitor-channel identification codes for each outlet SO_2 continuous emission monitoring system;

(ii) Date and hour;

(iii) Average hourly outlet SO_2 emission rate (lb/mmBtu, rounded to nearest hundredth);

(iv) For units with combustion controls, average daily inlet SO_2 emission rate (lb/mmBtu, rounded to nearest hundredth), determined by coal sampling and analysis procedures in Appendix F to this part; and

(v) For units with pre-combustion controls (i.e., fuel pretreatment), fuel analysis demonstrating the weight, sulfur content, and gross calorific value of the product and raw fuel lots.

(b) *Specific parametric data record provisions for calculating substitute emissions data for units with add-on emission controls.* In addition to the SO_2 and NO_x emission data to be recorded under § 75.50, the owner or operator of an affected unit with add-on emission controls where the owner or operator is using the approved site-specific parametric monitoring procedures for calculation of substitute data in accordance with § 75.34, then the owner or operator shall also record for each hour during each missing data period the applicable information in this paragraph (b):

(1) For units with add-on SO_2 emission controls, for each hour of missing SO_2 concentration or volumetric flow data:

(i) The information required in § 75.50(b) of this part for SO_2 concentration and volumetric flow if either one of these monitors is still operating;

(ii) Date and hour;

(iii) Number of operating scrubber modules;

(iv) Feedrate of makeup slurry to each operating scrubber module (gal/min);

(v) Average pressure differential across each operating scrubber module (inches of water column);

(vi) For a unit with a wet flue gas desulfurization system, an inline measure of absorber pH for each operating scrubber module;

(vii) For a unit with a dry flue gas desulfurization system, the inlet and outlet temperatures across each operating scrubber module;

(vii) The slurry feed rate (gal/min) to the atomizer nozzle; and

(ix) Method of determination of SO_2 concentration and volumetric flow, using Codes 1–12 in Table 3 of § 75.50 of this part.

(2) For units with add-on NO_x emission controls, for each hour of missing NO_x emission rate data:

(i) Date and hour;

(ii) Inlet air flow rate (acfh, rounded to the nearest thousand);

(iii) Excess O_2 concentration of flue gas at stack outlet (rounded to nearest tenth of a percent);

(iv) CO concentration of flue gas at stack outlet (ppm, rounded to the nearest tenth);

(v) Temperature of flue gas at furnace exit or economizer outlet duct (°F); and

(vi) Other parameters specific to NO_x emission controls (e.g., average hourly reagent feedrate).

(c) *Specific SO_2 Emission Record Provisions for Gas-Fired or Oil-Fired Units Using Optional Protocol in Appendix D to This Part.* In lieu of recording the information in § 75.50(c) of this section, the owner or operator shall record the applicable information in this paragraph for each affected gas-fired or oil-fired unit for which the owner or operator is using the optional protocol in Appendix D to this part for estimating SO_2 mass emissions.

(1) When the unit is combusting oil:

(i) Date and hour;

(ii) Average hourly flow rate of oil with the units in which oil flow is recorded, (gal/hr, lb/hr, or bbl/hr, rounded to the nearest tenth);

(iii) Sulfur content of daily oil sample, rounded to nearest tenth of a percent;

(iv) Method of oil sampling (flow proportional, continuous drip, or manual);

(v) Mass of oil combusted each hour (lb/hr, rounded to the nearest tenth); and

(vi) Average hourly SO_2 mass emissions (lb/hr, rounded to the nearest tenth).

(2) for gas-fired units or oil-fired units using the optional protocol in Appendix D of this part of daily manual oil sampling, when the unit is combusting oil, the highest sulfur content recorded from the most recent 30 daily oil samples rounded to nearest tenth of a percent.

(3) When the unit is combusting natural gas,

(i) Date and hour; and

(ii) Daily heat input from natural gas according to procedures in Appendix F to this part (mmBtu, rounded to the nearest tenth).

(iii) Sulfur content or SO_2 emission rate, in one of the following formats, in accordance with the appropriate procedure from Appendix D of this part:

(A) Sulfur content of daily gas sample, (rounded to the nearest 0.1 grains/100 scf) and the volume of gas combusted per day, in 100 scf; or

(B) SO_2 emission rate from NADB (in lb/mmBtu).

(d) *Specific NO_x Emission Record Provisions for Gas-Fired Peaking Units or Oil-Fired Peaking Units Using Optional Protocol in Appendix E of This Part.* In lieu of recording the information in paragraph § 75.50(d), the owner or operator shall record the applicable information in this paragraph for each affected gas-fired peaking unit or oil-fired peaking unit for which the owner or operator is using the optional protocol in Appendix E to this part for estimating NO_x emission rate.

(1) When the unit is combusting oil,

(i) Date and hour;

(ii) Average daily fuel flow of oil with the units in which oil flow is recorded (gal/day or bbl/day);

(iii) NO_x emission rate F-factor for oil combusted according to procedure in Appendix E to this part; and

(iv) Average daily NO_x emission rate (lb/mmBtu, rounded to nearest tenth).

(2) When the unit is combusting natural gas,

(i) Date and hour;

(ii) Average daily fuel flow of natural gas (million cubic ft);

(iii) NO_x emission rate F-factor for gas combusted according to procedure in Appendix E to this part; and

(iv) Average daily NO_x emission rate (lb/mmBtu, rounded to nearest tenth).

§ 75.52 Certification, quality assurance and quality control record provisions.

(a) The owner or operator shall record the applicable information in this section for each certified monitor or certified monitoring system (including certified backup or certified portable monitors) measuring and recording emissions or flow from an affected unit.

(1) For each SO_2 or NO_x pollutant concentration monitor, flow monitor, CO_2 monitor, or diluent gas monitor, the owner or operator shall record the following for all daily and 7-day calibration error tests, including any follow-up tests after corrective action:

(i) Monitor channel identification code;

(ii) Instrument span;

(iii) Date and hour;

(iv) Reference value, (i.e., calibration gas concentration or reference signal value, in ppm or other appropriate units);

(v) Observed value (monitor response during calibration, in ppm or other appropriate units);

(vi) Percent calibration error (rounded to nearest tenth of a percent);

(vii) Number of out-of-control hours, if any, following test; and

(viii) Description of any adjustments, corrective actions, or maintenance following test.

(2) For each flow monitor, the owner or operator shall record the following for all daily interference checks, including any follow-up tests after corrective action:

(i) Code indicating whether monitor passes or fails the interference check;

(ii) Number of out-of-control hours, if any, following test; and

(iii) Description of any adjustments, corrective actions, or maintenance following test.

(3) For each SO_2 or NO_x pollutant concentration monitor, CO_2 monitor, or diluent gas monitor, the owner or operator shall record the following for the initial and all subsequent linearity check(s), including any follow-up tests after corrective action:

(i) Monitor channel identification code;

(ii) Instrument span;

(iii) Date and hour;

(iv) Reference value (i.e., reference gas concentration, in ppm or other appropriate units);

(v) Observed value (average monitor response at each reference gas concentration, in ppm or other appropriate units);

(vi) Percent error at each of three reference gas concentrations (rounded to nearest tenth of a percent);

(vii) Number of out-of-control hours, if any, following test; and

(viii) Description of any adjustments, corrective action, or maintenance following test.

(4) For each flow monitor, where applicable, the owner or operator shall record the following for all quarterly leak checks, including any follow-up tests after corrective action:

(i) Code indicating whether monitor passes or fails the quarterly leak check;

(ii) Number of out-of-control hours, if any, following test; and

(iii) Description of any adjustments, corrective actions, or maintenance following test.

(5) For each SO_2 pollutant concentration monitor, flow monitor, CO_2 pollutant concentration monitor; NO_x continuous emission monitoring system, SO_2-diluent continuous emission monitoring system, and approved alternative monitoring system, the owner or operator shall record the following information for the initial and all subsequent relative accuracy tests and test audits:

(i) Date and hour;

(ii) Reference method(s) used;

(iii) Individual test run data from the relative accuracy test audit for the SO_2 concentration monitor, flow monitor, CO_2 pollutant concentration monitor, NO_x continuous emission monitoring system, SO_2-diluent continuous emission monitoring system, or approved alternative monitoring systems, including:

(A) Date, hour, and minute of beginning of test run,

(B) Date, hour, and minute of end of test run,

(C) Monitor-channel identification code,

(D) Run number,

(E) Run data for monitor;

(F) Run data for reference method; and

(G) Flag value (0 or 1) indicating whether run has been used in calculating relative accuracy and bias values.

(iv) Calculations and tabulated results, as follows:

(A) Arithmetic mean of the monitoring system measurement values, reference method values, and of their differences, as specified in Equation A–7 in appendix A to this part.

(B) Standard deviation, as specified in Equation A–8 in appendix A to this part.

(C) Confidence coefficient, as specified in Equation A–9 in appendix A to this part.

(D) Relative accuracy test results, as specified in Equation A–10 in appendix A to this part. (For the 3-level flow monitor test only, relative accuracy test results should be recorded at each of three gas velocities. Each of these three gas velocities shall be expressed as a total integrated gross unit load, rounded to the nearest MWe.)

(E) Bias test results as specified in section 7.6.4 in appendix A to this part.

(F) Bias adjustment factor from Equations A–11 and A–12 in appendix A to this part for any monitoring system or component that failed the bias test and 1.0 for any monitoring system or component that passed the bias test. (For flow monitors only, bias adjustment factors should be recorded at each of three gas velocities).

(G) Number of out-of-control hours, if any, following test.

(H) Description of any adjustment, corrective action, or maintenance following test.

(6) F-factor value(s) used to convert NO_x pollutant concentration and diluent gas (O_2 or CO_2) concentration measurements into NO_x emission rates (in lb/mmBtu), heat input or CO_2 emissions.

(7) Results of all trial runs and certification tests and quality assurance activities and measurements (including all reference method field test sheets, charts, records of combined system responses, laboratory analyses, and example calculations) necessary to substantiate compliance with all relevant appendices in this part.

§ 75.53 Monitoring plan.

(a) General provisions. The owner or operator of an affected unit shall prepare and maintain a monitoring plan. Except as provided in paragraphs (c) and (d) of this section, a monitoring plan shall contain sufficient information on the continuous emission or opacity monitoring systems and the use of data derived from these systems to demonstrate that all unit SO_2 emissions, NO_x emissions, CO_2 emissions when monitored continuously, and opacity are monitored and reported by continuous emission or opacity monitoring systems.

(b) Whenever the owner or operator makes a replacement, modification, or change, either in the certified continuous emission monitoring system or continuous opacity monitoring system, including the automated data acquisition and handling system or in the flue gas handling system, that requires recertification, then the owner or operator shall update the monitoring plan.

(c) Contents of the monitoring plan. Each monitoring plan shall contain the following:

(1) Precertification information, including the identification of the test strategy and protocol for the relative accuracy test audit and other relevant test information; and

(2) Unit table. A table identifying all units, using ORISPL numbers developed by the Department of Energy and used in the National Allowance Database, for all affected units involved in the monitoring plan with the following information for each unit:

(i) Short name;

(ii) Classification of unit as one of the following: Phase I affected (including substitution units), Phase II affected, new, or nonaffected;

(iii) Type of boiler (or boilers for a group of units using a common stack);

(iv) Type of fuel(s) fired, by boiler, and if more than one fuel, the fuel classification of the boiler;

(v) Type(s) of emission controls for SO_2, NO_x, and particulates installed or to be installed, including specifications of whether such controls are pre-combustion, post-combustion, or integral to the combustion process; and

(vi) Identification of all units using a common stack.

(3) Description of monitor site location. Description of site locations for each monitoring component in the continuous emission or opacity monitoring systems, including schematic diagrams and engineering drawings specified in paragraphs (c)(7) and (c)(8) of this section, and any other documentation that demonstrate each monitor location meets the appropriate siting criteria.

(4) Monitoring component table. Identification and description of each monitoring component (including each monitor and its identifiable components such as analyzer and/or probe) in the

continuous emission monitoring systems (i.e., SO_2 pollutant concentration monitor, flow monitor, moisture monitor; NO_x pollutant concentration monitor and diluent gas monitor) and the continuous opacity monitoring system, including:

(i) Manufacturer model number and serial number;

(ii) Monitor-channel identification code assigned by the utility to each monitor or identifiable monitoring component (such as the analyzer and/or probe). The code shall use a six-digit format, unique to each monitoring component, where the first three digits indicate the number of the component and the second three digits indicate the "channel" the particular parameter that the monitor measures;

(iii) Actual or projected installation date (month and year); and

(iv) A brief description of the component type or method of operation, such as in situ pollutant concentration monitor or thermal flow monitor.

(v) A brief description of the flow monitor that is sufficiently detailed to allow a determination of whether the applicable interference check design specification meets the requirements specified in Appendix A of this part.

(vi) A designation of the component as a primary or backup component, as provided for in § 75.10(g).

(5) Data acquisition and handling system table. Identification and description of all major hardware and software components of the automated data acquisition and handling system, including:

(i) For hardware components, the manufacturer, model number, and actual or projected installation date;

(ii) For software components, identification of the provider, whether the software is a custom, turn-key, or commercially available product, and a brief description of features;

(iii) A data flow diagram denoting the complete information handling path from output signals of continuous emission monitoring system components to final reports;

(iv) A copy of the test results verifying the accuracy of the automated data acquisition and handling system (once such results are available).

(6) Emissions formula table. A table giving explicit formulas for each reported unit emission parameter, using monitor-channel identification codes to link continuous emission monitoring system observations with reported concentrations, mass emissions, or emission rates, according to the conversions listed in appendix F to this part. The formulas must contain all constants and factors required to derive mass emissions or emission rates from monitor-channel code observations, and each emissions formula is identified with a unique three digit code.

(7) Schematic stack diagrams. A schematic diagram identifying entire gas handling system from boiler to stack for all affected units, using identification numbers for units, monitors, and stacks corresponding to the identification numbers provided in paragraphs (c)(2), (c)(4), (c)(5), and (c)(6) of this section. Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common stack.

(8) Stack and duct engineering diagrams. Stack and duct engineering diagrams showing the dimensions, and also showing location of fans, turning vanes, air preheaters, monitors, probes, reference method sampling ports and other equipment which affects the monitoring system location, performance or quality control checks.

(9) Inside crosssectional area (ft^2) at flue exit.

(10) Contents of monitoring plan for specific situations. The following information shall be included in the monitoring plan for gas-fired or oil-fired units:

(i) For each gas-fired unit or oil-fired unit for which the owner or operator uses the optional protocol in Appendix D of this part for estimating SO_2 mass emissions or Appendix E of this part for estimating NO_x emission rate (using a fuel flow meter), the designated representative shall include in the monitoring plan a description of the fuel flowmeter and data demonstrating its flow meter accuracy.

(ii) For each gas-fired peaking unit and oil-fired peaking unit for which the owner or operator uses the optional procedures in Appendix E to this part for estimating NO_x emission rate, the designated representative shall include in the monitoring plan:

(A) The NO_x emission rate F-factor for each fuel combusted by the unit; and

(B) All baseline and periodic NO_x emissions test data and results used to determine the NO_x emission rate F-factor for each fuel.

Subpart G—Reporting Requirements

§ 75.60 General provisions.

(a) The designated representative for any affected unit subject to the requirements of this part shall comply with all reporting requirements in this section and with the signatory requirements of § 72.21 of this chapter for all submissions.

(b) Submissions. The designated representative shall submit all reports and petitions (except as provided in § 75.61) as follows:

(1) All certification or recertification notifications, certification or recertification applications, monitoring plans, petitions for alternative monitoring systems, notifications, electronic quarterly reports, and other communications required by this subpart shall be submitted to the Administrator.

(2) Copies of certification or recertification notifications, certification or recertification applications and monitoring plans shall be submitted to the appropriate Regional Office of the U.S. Environmental Protection Agency and appropriate State or local air pollution control agency.

§ 75.61 Notification of certification and recertification test dates.

(a) *Submission.* The owner or operator or designated representative for an affected unit shall submit written notification of certification tests, recertification tests, and revised test dates for continuous emission monitoring systems, as specified in § 75.20 of this part. Certification test notifications shall be submitted not later than 45 days prior to the first day of certification or recertification testing, except as provided in § 75.20(a)(1)(ii) of this part. Recertification test notifications shall be provided as soon as practicable but not later than the second business day following the identified need for recertification.

(1) The owner or operator or designated representative shall notify the Administrator, the appropriate EPA Regional Office, and the applicable State air pollution control agency at least 7 business days in advance of any proposed adjustments to the certification testing dates.

(2) The owner or operator or designated representative shall submit notification of certification tests and recertification tests for continuous opacity monitoring systems, as specified in § 75.20(c)(6) of this part to the State or local air pollution control agency.

(3) If notification substantially similar to that required in this section is required by any other State or local agency, the owner or operator or designated representative may send the Administrator a copy of that notification to satisfy this requirement, provided the ORISPL unit identification number(s) is denoted.

(b) [Reserved]

§ 75.62 Monitoring plan.

(a) *Submission.* The designated representative for an affected unit shall submit the monitoring plan to the

Administrator no later than 45 days prior to the certification test.

(b) *Contents.* Monitoring plans shall contain the information specified in § 75.53 of this part.

§ 75.63 Certification or recertification application.

(a) *Submission.* The designated representative for an affected unit shall submit the request to the Administrator within 30 days after completing the certification test.

(b) *Contents.* Each application for certification or recertification shall contain the following information:

(1) A copy of the monitoring plan (or any modifications to the monitoring plan) for the unit or units if not previously submitted.

(2) The results of the test(s) required by § 75.20 of this part, including the type of test conducted, testing date, and including the results of any failed tests that had been repeated pursuant to the requirements in § 75.20.

(3) Results of the tests for verification of the accuracy of emissions and volumetric flow calculations performed by the automated data acquisition and handling system, including a summary of equations used to convert component data to units of the standard and to calculate substitute data for missing data periods, including sample calculations.

(c) *Electronic format.* Each certification application shall be submitted in a format to be specified by the Administrator.

§ 75.64 Quarterly reports.

(a) *Submission.* The designated representative for an affected unit shall electronically report the data and information in paragraphs (a), (b), and (c) of this section to the Administrator quarterly, beginning with the data from the later of: The last (partial) calendar quarter of 1993 (where the calendar quarter data begins at November 15, 1993); or the calendar quarter corresponding to the relevant deadline for certification in § 75.4 of this part. For any provisionally-certified monitoring system, some or all of the quarterly data may be invalidated, if the Administrator subsequently issues a notice of disapproval within 120 days of receipt of the complete certification application for the monitoring system. Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter and shall include for each affected unit (or group of units using a common stack):

(1) The information and hourly data required in §§ 75.50–75.52 of this part, excluding the descriptions of adjustments, corrective action, and maintenance and excluding any information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan, etc.).

(2) Tons (rounded to the nearest tenth) of SO_2 emitted during the quarter and cumulative SO_2 emissions for calendar year.

(3) Average NO_x emission rate (lb/mmBtu, rounded to the nearest hundredth) during the quarter and cumulative NO_x emission rate for calendar year.

(4) Tons of CO_2 emitted during quarter and cumulative CO_2 emissions for calendar year.

(5) Total heat input (mmBtu) and integrated gross unit load (MWge) for quarter and cumulative heat input and integrated gross unit load for calendar year.

(6) If the affected unit is using a qualifying Phase I technology, then the quarterly report shall include the information required in paragraph (e) of this section.

(b) The designated representative shall affirm that the monitor-channel identification codes and formulas in the quarterly electronic reports, submitted to the Administrator pursuant to § 75.53 of this part, represent current operating conditions.

(c) *Compliance certification.* The designated representative shall submit a certification in support of each quarterly emissions monitoring report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall indicate whether the monitoring data submitted were recorded in accordance with the applicable requirements of this part including the quality control and quality assurance procedures and specifications of this part and its appendices, and any such requirements, procedures and specifications of an applicable excepted or approved alternative monitoring method. In the event of any missing data periods, the certification must describe the measures taken to cure the causes for the missing data periods.

(d) *Electronic format.* Each quarterly report shall be submitted in a format to be specified by the Administrator.

(e) *Phase I qualifying technology reports.* In addition to reporting the information in paragraphs (a), (b), and (c) of this section, the designated representative for an affected unit on which SO_2 emission controls have been installed and operated for the purpose of meeting qualifying Phase I technology requirements pursuant to § 72.42 of this chapter shall also submit reports documenting the measured percent SO_2 emissions removal to the Administrator on a quarterly basis, beginning the first quarter of 1997 and continuing through the fourth quarter of 1999. Each report shall include the following information:

(1) For the first report only, a copy of the start up acceptance test result upon which the designated representative accepted the systems potential to meet the ninety percent reduction requirement.

(2) All measurements and calculations necessary to substantiate that the qualifying technology achieves the overall percent reduction in SO_2 emissions.

§ 75.65 Opacity reports.

The designated representative shall report excess emissions of opacity to the applicable State or local air pollution control agency, in a format specified by the applicable State or local air pollution control agency.

§ 75.66 Petitions to the Administrator.

(a) *Alternative flow monitor location demonstration reports.* In cases where no location exists for installation of a flow monitor in either the stack or the ducts serving an affected unit that satisfies the minimum physical siting criteria in Appendix A to this part or where installation of a flow monitor in either the stack or duct is demonstrated to the satisfaction of the Administrator to be technically infeasible, the designated representative for the affected unit may petition the Administrator for an alternative monitoring location or alternative method for monitoring volumetric flow. The demonstration report shall, at a minimum, contain the following information.

(1) Identification of the affected unit(s).

(2) Description of why the minimum siting criteria cannot be met within the existing ductwork or stack(s). This description shall include diagrams of the existing ductwork or stack, as well as documentation of any attempts to locate a flow monitor.

(3) Description of proposed alternative monitoring location or alternative method for monitoring flow.

(b) *Alternative ASTM method demonstration reports.* The designated representative for an affected unit may apply to the Administrator for an alternative to any ASTM method prescribed in this part. The designated representative shall include the following information in an application:

(1) A description of why the prescribed ASTM method is not being used;

(2) A description and diagram(s) of all equipment and procedures in the proposed alternative method;

(3) Data demonstrating that the proposed alternative method produces data of equal or greater precision and accuracy to that from the prescribed ASTM method(s).

(c) *Alternative monitoring system petitions.* The designated representative for an affected unit may submit a petition to the Administrator for approval and certification of an alternative monitoring system or component according to the procedure in subpart E of this part. Each petition shall contain the information and data specified in subpart E, including the information specified in § 75.48, in a format to be specified by the Administrator.

(d) *Parametric monitoring procedure petitions.* The designated representative for an affected unit may submit a petition to the Administrator, where each petition shall contain the information specified in § 75.51(b) for use of a parametric monitoring method.

(e) *Missing Data Petitions for units with add-on emission controls.* The designated representative for an affected unit may submit a petition to the Administrator, which the Administrator will automatically approve if the petition adequately demonstrates that all the requirements in § 75.34 are satisfied, where each petition shall contain the information listed below for the time period (or data gap) during which the affected unit experienced the monitor outage that would result in the substitution of an uncontrolled maximum value under the standard missing data procedures contained in subpart D of this part:

(1) Data demonstrating that the affected unit's monitor data availability for the time period under petition was less than 90%,

(2) Data demonstrating that the add-on emission controls were operating properly during time period under petition, and

(3) A list of the average hourly values for the previous 720 quality-assured monitor operating hours, highlighting both the maximum recorded value and the value corresponding to the maximum controlled emission rate.

(f) *Any other petitions to the Administrator.* The designated representative for an affected unit shall include sufficient information for the evaluation of any other petition submitted to the Administrator under this part.

§ 75.67 Retired units petitions.

For units that will be permanently retired prior to January 1, 1995, an exemption from the requirements of this part, including the requirement to install and certify a continuous emissions monitoring system, may be obtained from the Administrator if the designated representative submits a complete petition, as required in § 72.8, to the Administrator prior to the deadline in § 75.4 by which the continuous emission or opacity monitoring systems must complete the required certification tests.

Appendix A to Part 75—Specifications and Test Procedures

1. Installation and Measurement Location

1.1 Pollutant Concentration and CO_2 or O_2 Monitors

Following the procedures in section 3.1 of Performance Specification 2 in Appendix B to part 60 of this chapter, install the pollutant concentration monitor or monitoring system at a location where the pollutant concentration and emission rate measurements are directly representative of the total emissions from the affected unit. Select a representative measurement point or path for the monitor probe(s) (or for the path from the transmitter to the receiver) such that the SO_2 pollutant concentration monitor or NO_x continuous emission monitoring system (NO_x pollutant concentration monitor and diluent gas monitor) will pass the relative accuracy test (see section 6).

It is recommended that monitor measurements be made at locations where the exhaust gas temperature is above the dew-point temperature. If the cause of failure to meet the relative accuracy tests is determined to be the measurement location, relocate the monitor probe(s).

1.1.1 Point Pollutant Concentration and CO_2 or O_2 Monitors

Locate the measurement point (1) within the centroidal area of the stack or duct cross section, or (2) no less than 1.0 meter from the stack or duct wall.

1.1.2 Path Pollutant Concentration and CO_2 or O_2 Gas Monitors

Locate the measurement path (1) totally within the inner area bounded by a line 1.0 meter from the stack or duct will, or (2) such that at least 70.0 percent of the path is within the inner 50.0 percent of the stack or duct cross-sectional area, or (3) such that the path is centrally located within any part of the centroidal area.

1.2 Flow Monitors

Install the flow monitor in a location that provides representative volumetric flow over all operating conditions. Such a location is one that provides an average velocity of the flue gas flow over the stack or duct cross section, provides a representative SO_2 emission rate (in lb/hr), and is representative of the pollutant concentration monitor location. Where the moisture content of the flue gas affects volumetric flow measurements, use the procedures in both Reference Methods 1 and 4 of Appendix A to part 60 of this chapter to establish a proper location for the flow monitor. EPA recommends (but does not require) performing a flow profile study following the procedures in 40 CFR part 60, Appendix A, Text Method, 1, section 2.5 for each of the three operating or load levels indicated in section 6.5.2 of this appendix to determine the acceptability of the potential flow monitor location and to determine the number and location of flow sampling points required to obtain a representative flow value. The procedure in 40 CFR part 60, Appendix A, Test Method 1, section 2.5 may be used even if the flow measurement location is greater than or equal to 2 equivalent stack or duct diameters downstream or greater than or equal to ½ duct diameter upstream from a flow disturbance. If a flow profile study shows that cyclonic (or swirling) or stratified flow conditions exist at the potential flow monitor location that are likely to prevent the monitor from meeting the performance specifications of this part, then EPA recommends either (1) selecting another location where there is no cyclonic (or swirling) or stratified flow condition, or (2) eliminating the cyclonic (or swirling) or stratified flow condition by straightening the flow, e.g., by installing straightening vanes. EPA also recommends selecting flow monitor locations to minimize the effects of condensation, coating, erosion, or other conditions that could adversely affect flow monitor performance.

1.2.1 Acceptability of Monitor Location

The installation of a flow monitor is acceptable if (1) the location satisfies the minimum siting criteria of Method 1 in Appendix A to part 60 of this chapter (i.e., the location is greater than or equal to eight stack or duct diameters downstream and two diameters upstream from a flow disturbance; or, if necessary, two stack or duct diameters downstream and one-half stack or duct diameter upstream from a flow disturbance), (2) the results of a flow profile study, if performed, are acceptable (i.e., there are no cyclonic (or swirling) or stratified flow conditions), and (3) the flow monitor satisfies the performance specifications of this part. If the flow monitor is installed in a location that does not satisfy these physical criteria, but nevertheless the monitor achieves the performance specifications of this part, then the Administrator may certify the location as acceptable.

1.2.2 Alternative Monitoring Location

Whenever the flow monitor is installed in a location that is grater than or equal to two stack or duct diameters downstream and greater or equal to one-half diameter upstream from a flow disturbance, and/or in a location that is acceptable based on a flow profile study, but nevertheless the monitor does not achieve the performance specifications of this part, perform another flow profile study (the procedures described in section 2.5 of Method 1 in Appendix A to part 60 of this chapter may be used) to select an alternative flow monitoring installation site.

Whenever the owner or operator successfully demonstrates that modifications

to the exhaust duct or stack (such as installation of straightening vanes, modifications of ductwork, and the like) are necessary for the flow monitor to meet the performance specifications, the Administrator may approve an interim alternative flow monitoring methodology and an extension to the required certification date for the flow monitor.

Where no location exists that satisfies the physical siting criteria in section 1.2.1, where the results of flow profile studies performed at two or more alternative flow monitor locations are unacceptable, and where installation of a flow monitor in either the stack or the ducts is demonstrated to be technically infeasible, the owner or operator may petition the Administrator for an alternative method for monitoring flow.

2. Equipment Specifications

2.1 Instrument Span

In implementing sections 2.1.1 through 2.1.4 of this appendix, to the extent practicable, measure at a range such that the majority of readings obtained during normal operation are between 25 and 75 percent of full-scale range of the instrument.

2.1.1 SO_2 Pollutant Concentration Monitors

Determine, as indicated below, a span value for pollutant concentration monitors so that it includes all expected concentrations.

2.1.1.1 Maximum Potential Concentration

The monitor must be capable of accurately measuring up to 125 percent of the maximum potential concentration as calculated using Equation A–1a or A–1b. Calculate the maximum potential concentration by using Equation A–1a or A–1b and the maximum percent sulfur and minimum gross calorific value (GCV) for the highest sulfur fuel to be burned. Base the maximum percent sulfur and minimum GCV on the results of all available fuel sampling and analysis data from the previous 12 months (where such data exists) using ASTM Methods ASTM D3177–89, "Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke," ASTM D4239–85, "Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods," ASTM D4294–90, "Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy," ASTM D1552–90, "Standard Test Method for Sulfur in Petroleum Products (High Temperature Method)," ASTM D129–91, "Standard Test Method for Sulfur in Petroleum Products (General Bomb Method)," or ASTM D2622–92, "Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry" for sulfur content of solid or liquid fuels, or ASTM D3176–89, "Standard Practice for Ultimate Analysis of Coal and Coke", ASTM D240–87 (Reapproved 1991), "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter" or ASTM D2015–91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter" for GCV (incorporated by reference under § 75.6). Then, multiply the maximum potential concentration by 125 percent, and round up the resultant concentration to the nearest multiple of 100 ppm to determine the span value. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix, and to be greater than or equal to the span value. The span value will be used to determine the concentrations of the calibration gases. The selected monitor range based on 125 percent of the maximum potential concentration will henceforth be referred to as the "high-scale" of the SO_2 pollutant concentration monitor.

$$MPC = 11.32 \times 10^6 \left(\frac{\%S}{GCV}\right)\left(\frac{20.9-\%O_{2w}}{20.9}\right) \qquad \text{(Eq. A-1a)}$$

or

$$MPC = 66.93 \times 10^6 \left(\frac{\%S}{GCV}\right)\left(\frac{\%CO_{2w}}{100}\right) \qquad \text{(Eq. A-1b)}$$

where,

MPC=Maximum potential concentration (ppm, wet basis). To convert to dry basis, divide the MPC by 0.9.)

%S=Maximum sulfur content of fuel to be fired, wet basis, weight percent, as determined by ASTM D3177–89, ASTM D4239–85, ASTM D4294–90, ASTM D1552–90, ASTM D129–91, or ASTM D2622–92 for solid or liquid fuels (incorporated by reference under § 75.6).

GCV=Minimum gross calorific value of the fuel lot consistent with the sulfur analysis (Btu/lb), as determined using ASTM D3176–89, ASTM D240–87 (Reapproved 1991), or ASTM D2015–91 (incorporated by reference under § 75.6).

$\%O_{2w}$=Minimum oxygen concentration, percent wet basis, under normal operating conditions.

$\%CO_{2w}$=Maximum carbon dioxide concentration, percent wet basis, under normal operating conditions.

11.32×10^6=Oxygen-based conversion factor in (Btu/lb)(ppm)/%.

66.93×10^6=Carbon dioxide-based conversion factor in (Btu/lb)(ppm)/%

Note: All percent values to be inserted in the equations of this section are to be expressed as a percentage, not a fractional value, e.g., 3, not .03.

2.1.1.2 Maximum Expected Concentration

If the majority of SO_2 concentration values are predicted to be less than 25 percent of the full-scale range of the instrument based upon 125 percent of the maximum potential concentration, (e.g., at the outlet of an SO_2 emission control) use an additional (lower) monitor range. (For this second range, use Equation A–2 to calculate the maximum expected concentration (MEC). Multiply the maximum expected concentration by 125 percent, and round up the resultant concentration to the nearest multiple of 10 ppm to determine the span value. For this lower range, select the full-scale range of the instrument to be consistent with section 2.1 of this appendix, and to be greater than or equal to the lower range span value. Units using a lower range must also be capable of accurately measuring the anticipated actual concentrations up to and including 125 percent of the maximum potential concentration. The span value of this additional range will also be used to determine concentrations of the calibration gases for this additional range. The selected monitor range based on 125 percent of the maximum expected concentration will henceforth be referred to as the "low-scale" of SO_2 pollutant concentration monitors.

$$MEC = MPC[(100-RE)/100] \qquad \text{(Eq. A-2)}$$

where,

MEC=Maximum expected concentration (ppm).

MPC=Maximum potential concentration (ppm), as determined by Eq. A–1a or A–1b.

RE=Design removal efficiency of control equipment (%).

2.1.1.3 Auto-ranging Monitors

For monitors that can continuously and automatically adjust their range of measurement, the monitor must be capable at any time of accurately measuring up to 125

percent of the maximum potential concentration, as calculated using Equation A–1a or A–1b. Define the span value(s) for an auto-ranging monitor as 125 percent of the maximum potential concentration and 125 percent of the maximum expected concentration if a second span is determined to be necessary under section 2.1.1.2 of this appendix. Determine concentrations of the calibration gases based upon the span value(s).

2.1.1.4 Adjustment of Span

Wherever the SO_2 concentration exceeds the maximum potential concentration and the monitor can measure and record these values accurately, they may be reported for use in the Acid Rain Program. If the concentration exceeds the monitor's ability to measure and record values accurately, adjust the full-scale range setting to prevent future exceedances. Whenever the fuel supply or emission controls change such that the maximum expected or potential concentration may change significantly, adjust the range setting to assure the continued proper operation of the monitoring system. Whenever the range setting is adjusted, multiply the new range setting by 80 percent, and round up the resultant concentration to the nearest multiple of 100 ppm (or 10 ppm, if appropriate) to determine the new span value. Record the new span value and report the new span value as part of the results of the daily calibration error test required by Appendix B of this part. Whenever the span value is adjusted, use calibration gas concentrations based on the new span value.

2.1.2 NO_x Pollutant Concentration Monitors

Determine, as indicated below, a span value for the NO_x pollutant concentration monitor so that all expected NO_x concentrations can be determined and recorded accurately including both the maximum expected and potential concentration.

2.1.2.1 Maximum Potential Concentration

Use 800 ppm for coal-fired and 400 ppm for oil- or gas-fired units as the maximum potential concentration of NO_x. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix, and to be greater than or equal to the span value of 125 percent of the maximum potential concentration. If the maximum potential concentration is expected to be higher than the values stated above due to unit type (e.g. cyclone burner), or if it is determined through testing of the unit that the maximum potential concentration exceeds the above values, do one of the following: (1) Use a maximum potential concentration of 1600 ppm for coal-fired or 480 ppm for oil- or gas-fired units and set a span value of 125 percent of the maximum potential concentration (yielding a span value of 2000 ppm or 600 ppm); or (2) determine the maximum potential concentration based upon testing results and set the span value equal to 125 percent of the maximum potential concentration, rounding up to the nearest multiple of 100 ppm. The concentration of calibration gases is calculated as a percentage of the span value. The selected monitor range based on 125 percent of the maximum potential concentration will henceforth be referred to as the "high-scale" of the NO_x pollutant concentration monitor.

2.1.2.2 Maximum Expected Concentration

If the majority of NO_x concentrations are expected to be less than 25 percent of the full-scale range of the instrument based upon 125 percent of the maximum potential concentration, (e.g., at the outlet of a NO_x add-on emission control) use an additional "low-scale" monitor range. Use 320 ppm for coal-fired and 160 ppm for oil- or gas-fired units as the maximum expected concentration of NO_x. Calculate the span value of this second range by multiplying the maximum expected concentration by 125 percent (yielding 400 ppm or 200 ppm as the span value). If the efficiency of removal of an emission control is such that the maximum expected concentration, as determined by Equation A–2, differs by more than ±50 ppm from the values above, instead use the maximum expected concentration determined by Equation A–2. Calculate the span by multiplying the maximum expected concentration by 125 percent and round up the resultant concentration to the nearest multiple of 10 ppm. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix, and to be greater or equal to the lower range span value. The selected monitor range based on 125 percent of the maximum expected concentration will henceforth be referred to as the "low-scale" of NO_x pollutant concentration monitors. The span value of this additional range will also be used to determine the concentrations of the calibration gases for this additional range. NO_x pollutant concentration monitors on affected units with NO_x emission controls, or on other units with dual-span monitors, must also be capable of accurately measuring up to 125 percent of the maximum potential concentration. For dual-span NO_x pollutant concentration monitors, determine the concentration of calibration gases based on both span values.

2.1.2.3 Auto-ranging monitors

For monitors that can continuously and automatically adjust their range of measurement, the monitor must be capable at any time of accurately measuring up to 125 percent of the maximum potential concentration as defined in section 2.1.2.1 of this appendix. Define the span value(s) for an auto-ranging monitor as 125 percent of the maximum potential concentration and 125 percent of the maximum expected concentration if a second span is determined to be necessary under section 2.1.2.2 of this appendix. Determine concentrations of the calibration gases based upon the span value(s).

2.1.2.4 Adjustment of Span

Wherever the actual NO_x concentration exceeds the monitor's ability to measure and record values accurately, adjust the full-scale range setting to prevent future exceedances. Whenever the fuel supply, emission controls, or other process parameters change such that the maximum expected concentration or the maximum potential concentration may change significantly, adjust the NO_x pollutant concentration monitor range to assure the continued accuracy of the monitoring system. Whenever the range setting is adjusted, multiply the new range setting by 80 percent, and round up the resultant concentration to the nearest multiple of 100 ppm (or 10 ppm, if appropriate) to determine the new span value. Record the new span value, and report the new span value as part of the results of the daily calibration error test required by Appendix B of this part. Whenever the span value is adjusted, use calibration gas concentrations based on the new span value.

2.1.3 CO_2 and O_2 Monitors

Define the "high scale" span value as 20 percent O_2 or 20 percent CO_2. All O_2 and CO_2 analyzers must have "high-scale" measurement capability. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix, and to be greater than or equal to the span value. If the O_2 or CO_2 concentrations are expected to be consistently low, a "low scale" measurement range may be used for increased accuracy, provided that it is consistent with section 2.1 of this appendix. Multiply the "low-scale" range setting by 80 percent to determine the lower range span value, and determine the concentration of calibration gases based on both span values.

2.1.4 Flow Monitors

Select the full-scale range of the flow monitor so that it is consistent with section 2.1 of this appendix, and can accurately measure all potential volumetric flow rates at the flow monitor installation site. For this purpose, determine the span value of the flow monitor by multiplying the maximum potential velocity from previous tests or calculations by 125 percent, or using the following procedure. Calculate the maximum potential velocity (MPV) using Equation A–3a or A–3b. Multiply the MPV by 125 percent, and round up to the nearest multiple of 100 fpm to calculate the span value.

$$MPV = \left(\frac{F_d H_f}{A}\right)\left(\frac{20.9}{20.9 - \%O_{2d}}\right)\left[\frac{100}{(100 - \%H_2O)}\right]$$

or

$$MPV = \left(\frac{F_c H_f}{A}\right)\left(\frac{100}{\%CO_{2d}}\right)\left[\frac{100}{(100-\%H_2O)}\right] \quad \text{(Eq. A-3b)}$$

where:

MPV=maximum potential velocity (fpm, standard wet basis),

F_d=dry-basis F factor (dscf/mmBtu) from Table 1, Appendix F of this part,

F_c=carbon-based F factor ($scfCO_2$/mmBtu) from Table 1, Appendix F of this part,

H_f=maximum heat input (mmBtu/minute) for all units, combined, exhausting to the stack or duct where the flow monitor is located,

A=inside cross sectional area (ft^2) of the flue at the flow monitor location,

$\%O_{2d}$=maximum oxygen concentration, percent dry basis, under normal operating conditions,

$\%CO_{2d}$=minimum carbon dioxide concentration, percent dry basis, under normal operating conditions,

$\%H_2O$=maximum percent flue gas moisture content under normal operating conditions.

If the volumetric flow rate exceeds the flow monitor's ability to accurately measure and record values, adjust the full-scale range setting to prevent future exceedances. If the fuel supply, process parameters or other conditions change such that the maximum potential velocity may change significantly, adjust the range to assure the continued accuracy of the flow monitor. Whenever the range setting is adjusted, multiply the new range setting by 80 percent, and round up the resultant value to the nearest multiple of 100 fmp to determine the new span value. Record the new span value and reference values as parts of the results of the calibration error test required by Appendix B of this part. Whenever the span value is adjusted, use reference values for the calibration error test based on the new span value.

2.2 Design for Quality Control Testing

2.2.1 Pollutant Concentration and CO_2 or O_2 Monitors

Design and equip each pollutant concentration and CO_2 or O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (e.g., sample lines, filters, scrubbers, conditioners, and as much of the probe as practicable) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all active electronic and optical components (e.g. transmitter, receiver, analyzer).

Design and equip each pollutant concentration or CO_2 or O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero- and high-level concentrations specified in Section 5.2 of this Appendix.

2.2.2 Flow Monitors

Design all flow monitors to meet the applicable performance specifications.

2.2.2.1 Calibration Error Test

Design and equip each flow monitor to allow for a daily calibration error test consisting of at least two reference values: (1) Zero to 20 percent of span or an equivalent reference value (e.g., pressure pulse or electronic signal) and (2) 50 to 70 percent of span. Flow monitor response, both before and after any adjustment, must be capable of being recorded by the data acquisition and handling system. Design each flow monitor to allow a daily calibration error test of (1) the entire flow monitoring system, from and including the probe tip (or equivalent) through and including the data acquisition and handling system, or (2) the flow monitoring system from and including the transducer through and including the data acquisition and handling system.

2.2.2.2 Interference Check

Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver or equivalent.

Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic back purging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent velocity sensing interference, and (2) a means for detecting leaks in the system on at least a quarterly basis (manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (e.g., backpurging system) to prevent velocity sensing interference.

3. Performance Specifications

3.1 Calibration Error

The initial calibration error performance specification of SO_2 and NO_x pollutant concentration monitors shall not deviate from the reference value of the calibration gas by more than 2.5 percent based upon the span of the instrument, as calculated using Eq. A–5 of this appendix. Alternatively, where the span value is less than 200 ppm, calibration error test results are also acceptable if the absolute value of the difference between the monitor response value and the reference value, $|R-A|$ in Equation A–5 of this appendix, is less than or equal to 5 ppm. The calibration error of CO_2 or O_2 monitors shall not deviate from the reference value of the zero- or high-level calibration gas by more than 0.5 percent O_2 or CO_2 as calculated using the term $|R-A|$ in the numerator of Eq. A–5 of this appendix. The calibration error of flow monitors shall not exceed 3.0 percent based upon the span of the instrument as calculated using Eq. A–6 of this appendix.

3.2 Linearity Check

For SO_2 and NO_x pollutant concentration monitors, the error in linearity for each calibration gas concentration (low-, mid-, and high-levels) shall not exceed or deviate from the reference value by more than 5.0 percent (as calculated using Equation A–4 of this appendix). Linearity check results are also acceptable if the absolute value of the difference between the average of the monitor response values and the average of the reference values, $|R-A|$ in Equation A–4 of this appendix, is less than or equal to 5 ppm. For CO_2 or O_2 monitors:

(1) The error in linearity for each calibration gas concentration (low-, mid-, and high-levels) shall not exceed or deviate from the reference value by more than 5.0 percent as calculated using Equation A–4 of this appendix; or

(2) The absolute value of the difference between the average of the monitor response values and the average of the reference values, $|R-A|$ in Equation A–4 of this appendix, shall be less than or equal to 0.5 percent CO_2 or O_2, whichever is less restictive.

3.3 Relative Accuracy

3.3.1 Relative Accuracy for SO_2

The relative accuracy for SO_2 pollutant concentration monitors and for SO_2-diluent continuous emission monitoring systems used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999, shall not exceed 10.0 percent except as provided below in this section.

For affected units where the average of the monitor measurements of SO_2 concentration during the relative accuracy test audit is less than or equal to 250.0 ppm (or for SO_2-diluent monitors, less than or equal to 0.5 lb/mmBTU), the mean value of the monitor

measurements shall not exceed ±15.0 ppm of the reference method mean value (or, for SO_2-diluent monitors, not to exceed ±0.03 lb/mmBTU for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999) wherever the relative accuracy specification of 10.0 percent is not achieved.

3.3.2 Relative Accuracy for NO_x

The relative accuracy for NO_x continuous emission monitoring systems shall not exceed 10.0 percent.

For affected units where the average of the monitoring system measurements of NO_x emission rate during the relative accuracy test audit is less than or equal to 0.20 lb/mmBtu, the mean value of the NO_x continuous emission monitoring system measurements shall not exceed ±0.02 lb/mmBtu of the reference method mean value wherever the relative accuracy specification of 10.0 percent is not achieved.

3.3.3 Relative Accuracy for CO_2 Pollutant Concentration Monitors

The relative accuracy for CO_2 monitors shall not exceed 10 percent. The relative accuracy test results are also acceptable if the mean difference of the CO_2 monitor measurements and the corresponding reference method measurement, calculated using Equation A–7 of this appendix, is within ±1.0 percent CO_2 .

3.3.4 Relative Accuracy for Flow

Except as provided below in this section, the relative accuracy for flow monitors, where volumetric gas flow is measured in scfh, shall not exceed 15.0 percent through December 31, 1999. Beginning on January 1, 2000, (except as provided below in this section) the relative accuracy of flow monitors shall not exceed 10.0 percent.

For affected units where the average of the flow monitor measurements of gas velocity during one or more operating levels of the relative accuracy test audit is less than or equal to 10.0 fps, the mean value of the flow monitor velocity measurements shall not exceed ±2.0 fps of the reference method mean value in fps wherever the relative accuracy specification above is not achieved.

3.3.5 Combined SO_2/Flow Monitoring System [Reserved]

3.4 Bias

3.4.1 SO_2 Pollutant Concentration Monitors and NO_x Continuous Emission Monitoring Systems.

SO_2 pollutant concentration monitors and NO_x continuous emission monitoring systems shall not be biased low as determined by the test procedure in section 7.6 of this appendix. The bias specification applies to all SO_2 pollutant concentration monitors, including those measuring an average SO_2 concentration of 250.0 ppm or less, and to all NO_x continuous emission monitoring systems, including those measuring an average NO_x emission rate of 0.20 lb/mmBtu or less

3.4.2 Flow Monitors

Flow monitors shall not be biased low as determined by the test procedure in section 7.6 of this appendix. The bias specification applies to all flow monitors including those measuring an average gas velocity of 10.0 fps or less.

3.5 Cycle Time/Response Time

The cycle time/response time for pollutant concentration monitors, and continuous emission monitoring systems shall not exceed 15 min.

4. Data Acquisition and Handling Systems

Automated data acquisition and handling systems shall: (1) Read and record the full range of pollutant concentrations and volumetric flow from zero through span; and (2) provide a continuous, permanent record of all measurements and required information as an ASCII flat file capable of transmission via an IBM-compatible personal computer diskette or other electronic media. These systems also shall have the capability of interpreting and converting the individual output signals from an SO_2 pollutant concentration monitor, a flow monitor, and a NO_x continuous emissions monitoring system to produce a continuous readout of pollutant mass emission rates in the units of the standard. Where CO_2 emissions are measured with a continuous emission monitoring system, the data acquisition and handling system shall also produce a readout of CO_2 mass emissions in tons.

Data acquisition and handling systems shall also compute and record monitor calibration error; any bias adjustments to pollutant concentration, flow rate, or NO_x emission rate data; and all missing data procedure statistics specified in subpart D of this part.

5. Calibration Gas

5.1 Reference Gases

For the purposes of part 75, calibration gases include the following.

5.1.1 Standard Reference Materials

These calibration gases may be obtained from the National Institute of Standards and Technology (NIST) at the following address: Quince Orchard and Cloppers Road, Gaithersburg, Maryland 20899.

5.1.2 NIST/EPA-Approved Certified Reference Materials

A current list of certified reference material cylinder gases and certified reference material vendors is available from the Quality Assurance Division (MD 77), Environmental Monitoring System Laboratory, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

5.1.3 EPA Traceability Protocol 1 Gases

Protocol 1 gases must be vendor-certified to be within 2.0 percent of the concentration specified on the cylinder label (tag value).

5.2 Concentrations

Four concentration levels are required as follows.

5.2.1 Zero-level Concentration

0 to 20 percent of span, including span for high scale or both low- and high-scale for SO_2 and NO_x pollutant concentration monitors, as appropriate.

5.2.2 Low-level Concentration

20 to 30 percent of span, including span for high scale or both low- and high-scale for SO_2 and NO_x pollutant concentration monitors, as appropriate.

5.2.3 Mid-level Concentration

50 to 60 percent of span, including span for high scale or both low- and high-scale for SO_2 and NO_x pollutant concentration monitors, as appropriate.

5.2.4 High-level Concentration

80 to 100 percent of span, including span for high scale or both low- and high-scale for SO_2 and NO_x pollutant concentration monitors, as appropriate.

6. Certification Tests and Procedures

6.1 Pretest Preparation

Install the components of the continuous emission monitoring system (i.e., pollutant concentration monitors, CO_2 or O_2 monitor, and flow monitor) as specified in sections 1, 2, and 3 of this appendix, and prepare each system component and the combined system for operation in accordance with the manufacturer's written instructions. Operate the unit(s) during each period when measurements are made. Units may be tested on non-consecutive days.

6.2 Linearity Check

Measure the linearity of each pollutant concentration monitor and CO_2 or O_2 monitor according to the following procedures.

Challenge each pollutant concentration or CO_2 or O_2 monitor with NIST/EPA-approved certified reference material, standard reference material, or Protocol 1 calibration gases certified to be within 2 percent of the concentration specified on the label at the low-, mid-, or high-range concentrations specified in section 5.2 of this appendix. For units using emission controls and other units using a maximum expected concentration value to determine calibration gases, perform a linearity check on both the low- and high-scales.

Introduce the calibration gas at the gas injection port, as specified in section 2.2.1 of this appendix. Operate each monitor at its normal operating temperature and conditions. For extractive and dilution type monitors, pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as is practical. For in situ type monitors, perform calibration checking all active electronic and optical components, including the transmitter, receiver, and analyzer.

Repeat the procedure for SO_2 and NO_x pollutant concentration monitors using the low-scale for units equipped with emission controls with dual span monitors. Challenge the monitor three times with each reference gas. Do not use the same gas twice in succession. Record the monitor response from the data acquisition and handling system (see example data sheet in Figure 1). For each concentration, use the average of the responses to determine the error in linearity using Equation A–4 in this appendix.

Linearity checks are acceptable for monitor or monitoring system certification if none of

the test results exceed the applicable performance specifications in section 3.2 of this appendix.

6.3 7-Day Calibration Error Test

6.3.1 7-day Calibration Error Test for Pollutant Concentration Monitors and CO_2 and O_2 Monitors

Measure the calibration error of each pollutant concentration monitor and CO_2 or O_2 monitor once each day for 7 consecutive operating days according to the following procedures. (In the event that extended unit outages occur after the commencement of the test, the 7 consecutive operating days need not be 7 consecutive calendar days.) Units using dual span monitors must perform the calibration error test on both high- and low-scales of the pollutant concentration monitor.

Do not make manual adjustments to the monitor settings during the 7-day test. If automatic adjustments are made, conduct the calibration error test in a way that the magnitude of the adjustments can be determined and recorded.

The calibration error tests should, to the extent practicable, be approximately 24 hours apart, (unless the 7-day test is performed over non-consecutive days). Perform calibration error tests at two concentrations: (1) Zero-level and (2) high-level, as specified in section 5.2 of this appendix. In addition, repeat the procedure for SO_2 and NO_x pollutant concentration monitors using the low-scale for units equipped with emission controls or other units with dual span monitors. Use only NIST/EPA-approved certified reference material, standard reference material or Protocol 1 calibration gases certified by the vendor to be within 2 percent of the label value.

Introduce the calibration gas at the gas injection port, as specified in section 2.2.1 of this appendix. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as is practical. For in situ type monitors, perform calibration checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the pollutant concentration monitors and CO_2 or O_2 monitors once with each gas. Record the monitor response from the data acquisition and handling system. Using Equation A–5 of this appendix, determine the calibration error at each concentration once each day (at 24-hour intervals) for 7 consecutive days according to the procedures given in this section.

Calibration error tests are acceptable for monitor or monitoring system certification if none of these daily calibration error test results exceed the applicable performance specifications in section 3.1 of this appendix.

6.3.2 7-Day Calibration Error Test for Flow Monitors

Measure the calibration error of each flow monitor according to the following procedures.

Introduce the reference signal corresponding to the values specified in section 2.2.2.1 of this appendix to the probe tip (or equivalent), or to the transducer. During the 7-day certification test period, conduct the calibration error test once each day while the unit is operating (as close to 24-hour intervals as practicable). In the event that extended unit outages occur after the commencement of the test, the 7 consecutive operating days need not be 7 consecutive calendar days. Record the flow monitor responses by means of the data acquisition and handling system. Calculate the calibration error using Equation A–6 of this appendix.

Do not perform any corrective maintenance, repair, replacement or manual adjustment upon the flow monitor during the 7-day certification test period other than that required in the monitor operation and maintenance manual. If the flow monitor operates within the calibration error performance specification, (i.e., less than or equal to 3 percent error each day and does not require corrective maintenance, repair, replacement or manual adjustment during the 7-day test period) the flow monitor passes the calibration error test portion of the certification test. Wherever automatic adjustments are made, record the magnitude of the adjustments. Record all maintenance and required adjustments. Record output readings from the data acquisition and handling system before and after all adjustments.

6.4 Cycle Time/Response Time Test

Perform cycle time/response time tests for each pollutant concentration monitor, and continuous emission monitoring system according to the following procedures. Use a low-level and a high-level calibration gas (as defined in section 5.2 of this appendix) alternately. While the monitor or monitoring system is measuring and recording the concentration or emission rate, inject either a low-level concentration or a high-level concentration calibration gas into the injection port. Continue injecting the gas until a stable response is reached. Record the amount of time required for the monitor or monitoring system to complete 95.0 percent of the concentration or emission rate stepchange using data acquisition and handling system output. Then repeat the procedure with the other gas. For monitors or monitoring systems that perform a series of operations (such as purge, sample, and analyze), time the injections of the calibration gases so they will produce the longest possible response time. (Note: for the NO_x continuous emission monitoring system test and SO_2-diluent continuous emission monitoring system test, it will be necessary to simultaneously inject calibration gases into the pollutant and diluent monitors, in order to measure the step change in the lb/mmBtu emission rate.)

Cycle time/response time test results are acceptable for monitoring or monitoring system certification if none of the response times exceed 15 min.

6.5 Relative Accuracy and Bias Tests

Perform relative accuracy test audits for each CO_2 and SO_2 pollutant concentration monitor, each SO_2-diluent continuous emission monitoring system (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999, flow monitor, and NO_x continuous emission monitoring system. Record monitor or monitoring system output from the data acquisition and handling system. Perform concurrent relative accuracy test audits for each SO_2 pollutant concentration monitor and flow monitor, at least once a year (see section 2.3.1 of Appendix B of this part), during the flow monitor test at the normal operating level specified in section 6.5.2 of this appendix. Concurrent relative accuracy test audits may be performed by conducting simultaneous SO_2 and flow relative accuracy test audit runs, or by alternating an SO_2 relative accuracy test audit run with a flow relative accuracy test audit run until all relative accuracy test audit runs are completed. Where two or more probes are in the same proximity, care should be taken to prevent probes from interfering with each other's sampling. For each SO_2 pollutant concentration monitor, each flow monitor, and each NO_x continuous emission monitoring system, calculate bias, as well as relative accuracy, with data from the relative accuracy test audits.

Complete each relative accuracy test audit within a 7-day period while the unit (or units, if more than one unit exhausts into the flue) is combusting its primary fuel. When relative accuracy test audits are performed on continuous emission monitoring systems or component(s) on bypass stacks/ducts, use the fuel normally combusted by the unit (or units, if more than one unit exhausts into the flue) when emissions exhaust through the bypass stack/ducts. Do not perform corrective maintenance, repairs, replacements or adjustments during the relative accuracy test audit other than as required in the operation and maintenance manual.

6.5.1 SO_2 and CO_2 Pollutant Concentration Monitors and SO_2 and NO_x Continuous Emission Monitoring Systems

Perform relative accuracy test audits for each SO_2 or CO_2 pollutant concentration monitor or NO_x continuous emission monitoring system or SO_2-diluent continuous emission monitoring system (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999, at a normal operating level for the unit (or combined units, if common stack).

6.5.2 Flow Monitors

Except for flow monitors on bypass stacks/ducts and peaking units, perform relative accuracy test audits for each flow monitor at three different exhaust gas velocities, expressed in terms of percent of flow monitor span, or different operating or load levels. For a common stack/duct, the three different exhaust gas velocities may be obtained from frequently used unit/load combinations for units exhausting to the common stack. Select the operating levels as follows: (1) A frequently used low operating level selected

within the range between the minimum safe and stable operating level and 50% load, (2) a frequently used high operating level selected within the range between 80 percent of the maximum operating level and the maximum operating level, and (3) the normal operating level. If the normal operating level is within a specified range, [10.0 percent of the maximum operating level] of either (1) or (2) above, use a level that is evenly spaced between the low and high operating levels used. The maximum operating level shall be equal to the nameplate capacity less any physical or regulatory limitations or other deratings. Calculate flow monitor relative accuracy at each of the three operating levels. If a flow monitor fails the relative accuracy test on any of the three levels of a three-level relative accuracy test audit, the three-level relative accuracy test audit must be repeated. For flow monitors on bypass stacks/ducts and peaking units, the flow monitor relative accuracy test audit is required only at the normal operating level.

6.5.3 CO_2 Pollutant Concentration Monitors

Perform relative accuracy test audits for each CO_2 monitor (measuring in percent CO_2) at a normal operating level for the unit (or combined units, if common stack).

6.5.4 Calculations

Using the data from the relative accuracy test audits, calculate relative accuracy and bias in accordance with the procedures and equations specified in section 7 of this appendix.

6.5.5 Reference Method Measurement Location

Select a location for reference method measurements that is (1) accessible; (2) in the same proximity as the monitor or monitoring system location; and (3) meets the requirements of Performance Specification 2 in Appendix B to part 60 of this chapter for SO_2 and NO_x continuous emission monitoring systems, or Method 1 (or 1A) in Appendix A to part 60 of this chapter for volumetric flow, except as otherwise indicated in this section.

6.5.6 Reference Method Traverse Point Selection

Select traverse points that (1) ensure acquisition of representative samples of pollutant and diluent concentrations, moisture content, temperature, and flue gas flow rate over the flue cross section; and (2) meet the requirements of Performance Specification 2 in Appendix B to part 60 of this chapter (for SO_2 and NO_x), Method 1 (or 1A) (for volumetric flow), Method 3 (for O_2 CO_2 and dry molecular weight), and Method 4 (for moisture determination) in Appendix A to part 60 of this chapter.

6.5.7 Sampling Strategy

Conduct the reference method tests so they will yield results representative of the pollutant concentration, emission rate, moisture, temperature, and flue gas flow rate from the unit and can be correlated with the pollutant concentration monitor, CO_2 or O_2 monitor, flow monitor, and SO_2 or NO_x continuous emission monitoring system measurements. Conduct the diluent (O_2 or CO_2) measurements and any moisture measurements that may be needed simultaneously with the pollutant concentration and flue gas flow rate measurements. To properly correlate individual SO_2 and CO_2 pollutant concentration monitor data, SO_2 or NO_x continuous emission monitoring system data (in lb/mmBtu), and volumetric flow rate data with the reference method data, mark the beginning and end of each reference method test run (including the exact time of day) on the individual chart recorder(s) or other permanent recording device(s).

6.5.8 Correlation of Reference Method and Continuous Emission Monitoring System

Confirm that the monitor or monitoring system and reference method test results are on consistent moisture, pressure, temperature, and diluent concentration basis (e.g., since the flow monitor measures flow rate on a wet basis, Method 2 test results must also be on a wet basis). Compare flow-monitor and reference method results on a scfh basis. Also, consider the response times of the pollutant concentration monitor, the continuous emission monitoring system, and the flow monitoring system to ensure comparison of simultaneous measurements.

For each relative accuracy test audit run, compare the measurements obtained from the monitor or continuous emission monitoring system (in ppm, percent CO_2, lb/mmBtu, or other units) against the corresponding reference method values. Tabulate the paired data in a table such as the one shown in Figure 2.

6.5.9 Number of Reference Method Tests

Perform a minimum of nine sets of paired monitor (or monitoring system) and reference method test data for every required (i.e., certification, semiannual, or annual) relative accuracy or bias test audit. For the certification and annual quality assurance relative accuracy test audits for flow monitors, perform a minimum of nine sets at each of the three operating levels specified in section 6.5.2 of this appendix. Conduct each set within a period of 30 to 60 minutes.

Note: The tester may choose to perform more than nine sets of reference method tests. If this option is chosen, the tester may reject a maximum of three sets of the test results as long as the total number of test results used to determine the relative accuracy or bias is greater than or equal to nine. Report all data, including the rejected data, and reference method test results.

6.5.10 Reference Methods

The following methods from Appendix A to part 60 of this chapter or their approved alternatives are the reference methods for performing relative accuracy test audits: Method 1 or 1A for siting; Method 2 (or 2A, 2C, or 2D) for velocity; Methods 3, 3A, or 3B for O_2 or CO_2; Method 4 for moisture; Methods 6, 6A, or 6C for SO_2; Methods 7, 7A, 7C, 7D, 7E for NO_x; and Method 20 for determination of NO_x, SO_2, and O_2 or CO_2 from stationary gas turbines.

7. Calculations

7.1 Linearity Check

Analyze the linearity data for pollutant concentration and CO_2 or O_2 monitors as follows. Calculate the percentage error in linearity based upon the reference value at the low-level, mid-level, and high-level concentrations specified in section 6.2 of this appendix. Perform this calculation once during the certification test. Use the following equation to calculate the error in linearity for each reference value.

$$LE = \frac{|R-A|}{R} \times 100$$

(Eq. A–4)

where,

LE=Percentage Linearity error, based upon the reference value.

R=Reference value of Low-, mid-, or high-level calibration gas introduced into the monitoring system.

A=Average of the monitoring system responses.

7.2 Calibration Error

7.2.1 Pollutant Concentration and Diluent Monitors

For each reference value, calculate the percentage calibration error based upon instrument span for daily calibration error tests using the following equation:

$$CE = \frac{|R-A|}{S} \times 100$$

(Eq. A–5)

where,

CE=Percentage Calibration error based upon span of the instrument.

R=Reference value of zero- or high-level calibration gas introduced into the monitoring system.

A=Actual monitoring system response to the calibration gas.

S=Span of the instrument, as specified in Section 2 of this appendix.

7.2.2 Flow Monitor Calibration Error

For each reference value, calculate the percentage calibration error based upon span using the following equation:

$$CE = \frac{|R-A|}{S} \times 100$$

(Eq. A–6)

where,

CE=Calibration error;

R=Low or high level reference value specified in section 2.2.2.1 of this appendix;

A=Actual flow monitor response to the reference value; and

S=Flow monitor span.

Whenever the flow rate exceeds the monitor's ability to measure and record values accurately, adjust the span to prevent future exceedances. If process parameters change or other changes are made such that the expected flue gas velocity may change significantly, adjust the span to assure the continued accuracy of the monitoring system.

7.3 Relative Accuracy for SO_2 and CO_2 Pollutant Concentration Monitors, SO_2 Continuous Emission Monitoring Systems, and Flow Monitors

Analyze the relative accuracy test audit data from the reference method tests for SO_2 and CO_2 pollutant concentration monitors, SO_2-diluent continuous emission monitoring systems (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999, and flow monitors using the following procedures. Summarize the results on a data sheet. An example is shown in Figure 2. Calculate the mean of the monitor or monitoring system measurement values. Calculate the mean of the reference method values. Using data from the automated data acquisition and handling system, calculate the arithmetic differences between the reference method and monitor measurement data sets. Then calculate the arithmetic mean of the differences, the standard deviation, the confidence coefficient, and the monitor or monitoring system relative accuracy using the following procedures and equations.

7.3.1 Arithmetic Mean

Calculate the arithmetic mean of the differences, $\bar{d}$, of a data set as follows.

$$\bar{d} = \frac{1}{n}\sum_{i=1}^{n} d_i$$

(Eq. A–7)

where,

n=Number of data points.

$\sum_{i=1}^{n} d_i$=Algebraic sum of the individual differences d_i.

d_i=The difference between a reference method value and the corresponding continuous emission monitoring system value (RM_i–CEM_i) at a given point in time i.

When calculating the arithmetic mean of the difference of a flow monitor data set, be sure to correct the monitor measurements for moisture if applicable.

7.3.2 Standard Deviation

Calculate the standard deviation, S_d, of a data set as follows:

$$S_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - \left[\frac{\left(\sum_{i=1}^{n} d_i\right)^2}{n}\right]}{n-1}}$$

(Eq. A–8)

7.3.3 Confidence Coefficient

Calculate the confidence coefficient (one-tailed), cc, of a data set as follows.

$$cc = t_{0.025}\frac{S_d}{\sqrt{n}}$$

(eq. A–9)

where,

$t_{0.025}$=t value (see Table 7–1).

TABLE 7–1 T-VALUES

n-1	$t_{0.025}$	n-1	$t_{0.025}$	n-1	$t_{0.025}$
1	12.706	12	2.179	23	2.069
2	4.303	13	2.160	24	2.064
3	3.182	14	2.145	25	2.060
4	2.776	15	2.131	26	2.056
5	2.571	16	2.120	27	2.052
6	2.447	17	2.110	28	2.048
7	2.365	18	2.101	29	2.045
8	2.306	19	2.093	30	2.042
9	2.262	20	2.086	40	2.021
10	2.228	21	2.080	60	2.000
11	2.201	22	2.074	>60	1.960

7.3.4 Relative Accuracy

Calculate the relative accuracy of a data set using the following equation.

$$RA = \frac{|\bar{d}| + |cc|}{\overline{RM}} \times 100$$

(Eq. A–10)

where,

RM=Arithmetic mean of the reference method values.

|d|=The absolute value of the mean difference between the reference method values and the corresponding continuous emission monitoring system values.

|cc|=The absolute value of the confidence coefficient.

7.4 Relative Accuracy for NO_x Continuous Emission Monitoring Systems

Analyze the relative accuracy test audit data from the reference method tests for NO_x continuous emissions monitoring system as follows.

7.4.1 Data Preparation

If C_{NOx}, the NO_x concentration, is in ppm, multiply it by 1.194×10^{-7} (lb/dscf)/ppm to convert it to units of lb/dscf. If C_{NOx} is in mg/dscm, multiply it by 6.24×10^{-8} (lb/dscf)/(mg/dscm) to convert it to lb/dscf. Then, use the diluent (O_2 or CO_2) reference method results for the run and the appropriate F or F_c factor from Table 1 in Appendix F of this part to convert C_{NOx} from lb/dscf to lb/mmBtu units. Use the equations and procedure in section 3 of Appendix F to this part, as appropriate.

7.4.2 NO_x Emission Rate (Monitoring System)

For each test run in a data set, calculate the average NO_x emission rate (in lb/mmBtu), by means of the data acquisition and handling system, during the time period of the test run. Tabulate the results as shown in example Figure 4.

7.4.3 Relative Accuracy

Use the equations and procedures in section 7.3 above to calculate the relative accuracy for the NO_x continuous emission monitoring system. In using Equation A–7, "d" is, for each run, the difference between the NO_x emission rate values (in lb/mmBtu) obtained from the reference method data and the NO_x continuous emission monitoring system.

7.5 Relative Accuracy for Combined SO_2/Flow [Reserved]

7.6 Bias Test and Adjustment Factor

Test the relative accuracy test audit data sets for SO_2 pollutant concentration monitors, flow monitors, and NO_x continuous emission monitoring systems for bias using the procedures outlined below.

7.6.1 Arithmetic Mean

Calculate the arithmetic mean of the difference, $\bar{d}$, of the data set using Equation A–7 of this appendix. To calculate bias for an SO_2 pollutant concentration monitor, "d" is, for each paired data point, the difference between the SO_2 concentration value (in ppm) obtained from the reference method and the monitor. To calculate bias for a flow monitor, "d" is, for each paired data point, the difference between the flow rate values (in scfh) obtained from the reference method and the monitor. To calculate bias for a NO_x continuous emission monitoring system, "d" is, for each paired data point, the difference between the NO_x emission rate values (in lb/mmBtu) obtained from the reference method and the monitoring system.

7.6.2 Standard Deviation

Calculate the standard deviation, S_d, of the data set using Equation A–8.

7.6.3 Confidence Coefficient

Calculate the confidence coefficient, cc, of the data set using Equation A–9.

7.6.4 Bias Test

If the mean difference, $\bar{d}$, is greater than the absolute value of the confidence coefficient, |cc|, the monitor or monitoring system has failed to meet the bias test requirement. For flow monitor bias tests, if the mean difference, $\bar{d}$, is greater than |cc| at the normal operating level (or equally spaced intermediary level), the monitor has failed to meet the bias test requirement. For flow monitors, apply the bias test at normal operating level (or an evenly spaced intermediary level).

7.6.5 Bias Adjustment

If the monitor or monitoring system fails to meet the bias test requirement, adjust the value obtained from the monitor using the following equation:

$CEM_i^{Adjusted} = CEM_i^{Monitor} \times BAF$

(Eq. A–11)

where,

$CEM_i^{Monitor}$=Data (measurements) provided by the monitor at time i.

$CEM_i^{Adjusted}$=Data value, adjusted for bias, at time i.

BAF=Bias adjustment factor, defined by

$$BAF = 1 + \frac{|\bar{d}|}{CEM}$$

(Eq. A–12)

where,

$\bar{d}$=Arithmetic mean of the difference obtained during the failed bias test using Equation A–7.

CEM=Mean of the data values provided by the monitor during the failed bias test.

If the bias test is failed by a flow monitor on a 3-level relative accuracy test audit, calculate the bias adjustment factor for each of the three operating levels. Apply the largest of the three bias adjustment factors to subsequent flow monitor data using Equation A–11.

Apply this adjustment prospectively to all monitor or monitoring system data from the date and time of the failed bias test until the date and time of a relative accuracy test audit that does not show bias. Use the adjusted values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the emitted tons of SO_2 and CO_2 and the average NO_x emission rate during the quarter and calendar year, as specified in subpart G of this part.

FIGURE 1.—LINEARITY ERROR DETERMINATION

Day	Date and time	Reference value	Monitor value	Difference	Percent of reference value
Low-level					
Mid-level					
High-level					

FIGURE 2.—RELATIVE ACCURACY DETERMINATION (POLLUTANT CONCENTRATION MONITORS)

Run No.	Date and time	SO_2 (ppm[c])			Date and time	CO_2 (Pollutant) (ppm[c])		
		RM[a]	M[b]	Diff		RM[a]	M[b]	Diff
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
Arithmetic Mean Difference (Eq. A–7).								
Confidence Coefficient (Eq. A–9).								
Relative Accuracy (Eq. A–10).								

[a] RM means "reference method data."
[b] M means "monitor data."
[c] Make sure that RM and M data are on a consistent basis, either wet or dry.

FIGURE 3.–RELATIVE ACCURACY DETERMINATION (FLOW MONITORS)

Run No.	Date and time	Flow rate (Low) (scf/hr) *			Date and time	Flow rate (Normal) (scf/hr) *			Date and time	Flow rate (High) (scf/hr) *		
		RM	M	Diff		RM	M	Diff		RM	M	Diff
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
Arithmetic Mean Difference (eq. A–7). Confidence Coefficient (eq. A–9). Relative Accuracy (eq. A–10).												

*Make sure that RM and M data are on a consistent moisture basis.

FIGURE 4:—RELATIVE ACCURACY DETERMINATION (NO_x/diluent combined system)

Run No.	Date and time	Reference method data		NO_x system (lb/mmBtu)		
		NO_x ( )*	O_2/CO_2%	RM	M	Difference
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
Arithmetic Mean Difference (eq. A–7).						

FIGURE 4:—RELATIVE ACCURACY DETERMINATION (NO_x/diluent combined system)—Continued

Run No.	Date and time	Reference method data		NO_x system (lb/mmBtu)		
		NO_x ( )*	O_2/CO_2%	RM	M	Difference
Confidence Coefficient (eq. A–9). Relative Accuracy (eq. A–10).						

*Specify units: ppm, lb/dscf,mg/dscm.

Appendix B to Part 75—Quality Assurance and Quality Control Procedures

1. Quality Control Program

Develop and implement a quality control program for the continuous emission monitoring systems and their components. As a minimum, include in each quality control program a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities.

1.1 Calibration Error Test and Linearity Check Procedures

Identify calibration error test and linearity check procedures specific to the continuous emission monitoring system that may require variance from the procedures in Appendix A to this part (e.g., how gases are to be injected, adjustments of flow rates and pressures, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error or error in linearity, determination of interferences, and when calibration adjustments should be made).

1.2 Calibration and Linearity Adjustments

Explain how each component of the continuous emission monitoring system will be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of each continuous emission monitoring system.

1.3 Preventive Maintenance

Keep a written record of procedures, including those specified by the manufacturers, needed to maintain the continuous emission monitoring system in proper operating condition and a schedule for those procedures. Include provisions for maintaining an inventory of spare parts.

1.4 Audit Procedures

Keep a written record of procedures and details peculiar to the installed continuous emission monitoring system that are to be used for relative accuracy test audits, such as sampling and analysis methods.

1.5 Recordkeeping and Reporting

Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements in subparts F and G of this part.

2. Frequency of Testing

A summary chart showing each quality assurance test and the frequency at which each test is required is located at the end of this appendix in Figure 1.

2.1 Daily Assessments

For each monitor or continuous emission monitoring system, perform the following assessments during each day in which the unit combusts any fuel (hereafter referred to as a "unit operating day"), or for a monitor or continuous emission monitoring system on a bypass stack/duct, during each day that emissions pass through the by-pass stack or duct. These requirements are effective as of the date when the monitor or continuous emission monitoring system completes certification testing.

2.1.1 Calibration Error Test for Pollutant Concentration and CO_2 or O_2 Monitors

Test, record, and compute the calibration error of each SO_2 or NO_x pollutant concentration and CO_2 or O_2 monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass ducts/stacks, on each day that emissions pass through the by-pass stack or duct. Conduct calibration error checks, to the extent practicable, approximately 24 hours apart. Perform the daily calibration error test according to the procedure in Appendix A, section 6.3.1 of this part.

For units with add-on emission controls and dual span or auto-ranging monitors, and other units that use maximum expected concentration value to determine calibration gas values, perform the daily calibration error test on each scale that has been used since the previous calibration error test. For example, if the emissions concentration has not exceeded the low-scale span value, (based on the maximum expected concentration) since the calibration test during the previous calendar day, the calibration error test may be performed on the low-scale only. If, however, the emissions concentration has exceeded the low-scale span value for one hour or longer since the previous calibration error test, perform the calibration error on both the low- and high-scales.

2.1.2 Calibration Error Test for Flow Monitors

Test, compute, and record the calibration error of each flow monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass ducts/stacks, on each day that emissions pass through the by-pass stack or duct. Introduce the reference values (specified in section 2.2.2.1 of Appendix A to this part) to the probe tip (or equivalent) or to the transducer. Record flow monitor output from the data acquisition and handling system before and after any adjustments to the flow monitor. Keep a record of all maintenance and adjustments. Calculate the calibration error using Equation A–6 in Appendix A of this part.

2.1.3 Interference Check

Perform the daily flow monitor interference checks specified in section 2.2.2.2 of Appendix A to this part at least once per operating day (when the unit(s) operate for any part of the day).

2.1.4 Recalibration

Adjust the calibration, at a minimum, whenever the daily calibration error exceeds the limits of the applicable performance specification for the pollutant concentration monitor, CO_2, or O_2 monitor, or flow monitor in Appendix A of this part. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective.

2.1.5 Out-of-Control Period

An out-of-control period occurs when the calibration error of an SO_2 or NO_x pollutant concentration monitor exceeds 5.0 percent based upon the span value (or exceeds 10 ppm, for span values <200 ppm), when the calibration error of a diluent gas monitor exceeds 1.0 percent O_2 or CO_2, or when the calibration error of a flow monitor exceeds 6.0 percent based upon the span value, which is twice the applicable specification of Appendix A of this part. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out of control if 2 or more valid readings are obtained during that hour as required by § 75.10 of this part. A NO_x continuous emission monitoring system is considered out-of-control if either component monitor exceeds twice the applicable specification in Appendix A of this part.

An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of completion of the failed interference check and ends with the hour of completion of an interference check that is passed.

2.1.6 Data Recording

Record and tabulate all calibration error test data according to month, day, clock-hour, and magnitude in either ppm, percent volume, or scfh. Program monitors that automatically adjust data to the corrected

calibration values (e.g., microprocessor control) to record either: (1) The unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) Sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2.2 Quarterly Assessments

For each monitor or continuous emission monitoring system, perform the following assessments during each calendar quarter in which the unit combusts any fuel (hereafter referred to as a "unit operating quarter"), or for monitors or monitoring systems on bypass ducts/stacks, during each calendar quarter that emissions pass through the by-pass stack or duct (hereafter referred to as a "bypass operating quarter"). This requirement is effective as of the calendar quarter following the calendar quarter in which the monitor or continuous emission monitoring system is provisionally certified.

2.2.1 Linearity Check

Perform a linearity check for each SO_2 and NO_x pollutant concentration monitor and each CO_2 or O_2 monitor at least once during each unit operating quarter or each bypass operating quarter, in accordance with the procedures in Appendix A, section 6.2 of this part. For units using emission controls and other units using a low-scale span value to determine calibration gases, perform a linearity check on both the low- and high-scales. For the linearity check, use calibration gas cylinders that are different cylinders from the ones used in the daily calibration error tests. Conduct the linearity checks no less than 2 months apart.

2.2.2 Leak Check

For differential pressure flow monitors, perform a leak check of all sample lines (a manual check is acceptable) at least once during each unit operating quarter or each bypass operating quarter. Conduct the leak checks no less than 2 months apart.

2.2.3 Out-of-Control Period

An out-of-control period occurs when the error in linearity at any of the three concentrations (six for dual range monitors) in the quarterly linearity check exceeds the applicable specification in Appendix A, section 3.2 of this part. The out-of-control period begins with the hour of the failed linearity check and ends with the hour of a satisfactory linearity check following corrective action and/or monitor repair. For the NO_x continuous emission monitoring system, the system is considered out-of-control if either of the component monitors exceed the applicable specification in Appendix A, section 3.2 of this part. An out-of-control period occurs when a flow monitor sample line leak is detected. The out-of-control period begins with the hour of the failed leak check and ends with the hour of a satisfactory leak check following corrective action.

2.3 Semiannual and Annual Assessments

For each monitor or continuous emission monitoring system, perform the following assessments once semiannually or once annually after the calendar quarter in which the monitor or monitoring system was last tested, as specified below for the type of test and the performance achieved. For monitors or continuous emission monitoring systems on bypass ducts/stacks, the assessments are to be performed once every two successive bypass operating quarters or once every four successive operating quarters after the calendar quarter in which the monitor or monitoring system was last tested, as specified below for the type of test and the performance achieved. This requirement is effective as of the calendar quarter or bypass operating quarter following the calendar quarter in which the monitor or continuous emission monitoring system is provisionally certified. A summary chart showing the frequency with which a relative accuracy test audit must be performed, depending on the accuracy achieved, is located at the end of this appendix in Figure 2.

23.1 Relative Accuracy Test Audit

Perform relative accuracy test audits semiannually and no less than 4 months apart for each SO_2 or CO_2 pollutant concentration monitor, flow monitor, NO_x continuous emission monitoring system, for SO_2-diluent continuous emission monitoring systems used by units with a Phase I Qualifying technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999, in accordance with the procedures in section 6.5 of Appendix A of this part. For monitors on bypass stacks/ducts, perform relative accuracy test audits once every two successive bypass operating quarters in accordance with the procedures in section 6.5 of Appendix A of this part. Successive audits shall be no less than 4 months apart. The audit frequency may be reduced, as specified below for monitors or monitoring systems which qualify for less frequent testing.

For flow monitors, one-level and three-level relative accuracy test audits shall be performed alternately (when a flow RATA is conducted semiannually), such that the three-level relative accuracy test audit is performed at least once annually. The three-level audit shall be performed at the three different operating or load levels specified in Appendix A, section 6.5.2 of this part, and the one-level audit shall be performed at the normal operating or load level. Relative accuracy test audits need only be performed once every two successive unit or bypass operating quarters at the normal operating or load level for monitors and continuous emission monitoring systems on peaking units and bypass stacks/ducts.

Relative accuracy test audits may be performed on an annual basis rather than on a semiannual basis under any of the following conditions (or for monitors on peaking units and bypass ducts/stacks, once every four successive unit or bypass operating quarters): (1) The relative accuracy during the previous audit for an SO_2 or CO_2 pollutant concentration monitor, or NO_x or SO_2 continuous emissions monitoring system is 7.5 percent or less; (2) prior to January 1, 2000, the relative accuracy during the previous audit for a flow monitor is 10.0 percent or less at each operating level tested; (3) on and after January 1, 2000, the relative accuracy during the previous audit for a flow monitor is 7.5 percent or less at each operating level tested; (4) on low flow (≤10.0 fps) stacks/ducts, when the monitor mean, calculated using Equation A–7 in Appendix A of this part is within ±1.5 fps of the reference method mean or achieves a relative accuracy of 7.5 percent (10 percent if prior to January 1, 2000) or less during the previous audit; (5) on low SO_2 emitting units (SO_2 concentrations ≤250.0 ppm), when the monitor mean is within ±8.0 ppm (or equivalent in lb/mmBTU for SO_2-diluent monitors) of the reference method mean or achieves a relative accuracy of 7.5 percent or less (or equivalent lb/mmBTU value for SO_2-diluent monitors) during the previous audit; or (6) on low NO_x emitting units (NO_x emission rate ≤0.20 lb/mmbtu), when the NO_x continuous emission monitoring system achieves a relative accuracy of 7.5 percent or less.

A maximum of two relative accuracy test audit trials may be performed for the purpose of achieving the results required to qualify for less frequent relative accuracy test audits. Whenever two trials are performed, the results of the second (later) trial must be used in calculating both the relative accuracy and bias.

2.3.2 Out-of-Control Period

An out-of-control period occurs under any of the following conditions: (1) The relative accuracy of an SO_2 pollutant concentration monitor or a NO_x or SO_2 continuous emission monitoring system exceeds 10.0 percent; (2) prior to January 1, 2000, the relative accuracy of a flow monitor exceeds 15.0 percent; (3) on and after January 1, 2000, the relative accuracy of a flow monitor exceeds 10.0 percent; (4) for low flow situations (≤10.0 fps), the flow monitor mean value (if applicable) exceeds±2.0 fps of the reference method mean whenever the relative accuracy is greater than 15.0 percent for Phase I or 10 percent for Phase II; (5) for low SO_2 emitter situations, the monitor mean values exceeds ±15.0 ppm of the reference method mean whenever the relative accuracy is greater than 10.0 percent; or (6) for low NO_x emitting units (NO_x emission rate ≤0.2 lb/mmbtu), the NO_x continuous emission monitoring system mean values exceed ±0.02 lb/mmBtu of the reference method mean whenever the relative accuracy is greater than 10.0 percent. For SO_2, NO_x emission rate, and flow relative accuracy test audits performed at only one level, the out-of-control period begins with the hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit. For a flow relative accuracy test audit at 3 operating levels, the out-of-control period begins with the hour of completion of the first failed relative accuracy test audit at any of the three operating levels, and ends with the hour of completion of a satisfactory three-level relative accuracy test audit.

Failure of the bias test does not result in the system or monitor being out-of-control.

the bias adjustment factor given in Equations A–11 and A–12 of Appendix A to this part to adjust the monitored data.

2.4 Other Audits

Affected units may be subject to relative accuracy test audits at any time. If a monitor or continuous emission monitoring system fails the relative accuracy test during the audit, the monitor or continuous emission monitoring system shall be considered to be out-of-control beginning with the date and time of completion of the audit, and continuing until a successful audit test is completed following corrective action. If a monitor or monitoring system fails the bias test during an audit, use the bias adjustment factor given by Equations A–11 and A–12 in Appendix A to this part to adjust the monitored data. Apply this adjustment factor from the date and time of completion of the audit until the date and time of completion of a relative accuracy test audit that does not show bias.

FIGURE 1.—QUALITY ASSURANCE TEST REQUIREMENTS

Test	QA test frequency requirements		
	Daily*	Quarterly*	Semiannual*
Calibration Error (2 pt.).	√		
Interference (flow).	√	√	
Linearity (3 pt.).		√	

FIGURE 1.—QUALITY ASSURANCE TEST REQUIREMENTS—Continued

Test	QA test frequency requirements		
	Daily*	Quarterly*	Semiannual*
RATA (SO_2, NO_x, CO_2)[1].			√
RATA (flow, alternating 1-load and 3-load)[2].			√

*For monitors on bypass stack/duct, bypass operating days or quarters, only.
[1]Conduct annually, if monitor meets accuracy requirements to qualify for less frequent testing.
[2]Conduct 3-load RATAs annually, if requirements to qualify for less frequent testing are met.

FIGURE 2.—RELATIVE ACCURACY TEST FREQUENCY INCENTIVE SYSTEM

RATA	Semiannually*	Annual*
SO_2	RA ≤ 10%	RA ≤ 7.7% or ± 8ppm**
NO_x	RA ≤ 10%	RA ≤ 7.5%
Flow (Phase I)[3]	RA ≤ 15%	RA ≤ 10% or ± 1.5 fps**
Flow (Phase II)[3]	RA ≤ 10%	RA ≤ 7.5% or ± 1.5 fps**

*For monitors on bypass stack/duct, bypass operating quarters, only.
**The difference between monitor and reference method mean values; low emitters or low flow, only.
[3]Conduct 3-load RATAs annually, if requirements to qualify for less frequent testing are met.

Appendix C to Part 75—Missing Data Estimation Procedures

1. Parametric Monitoring Procedure for Missing SO_2 Concentration or NO_x Emission Rate Data

1.1 Applicability

The owner or operator of any affected unit equipped with post-combustion SO_2 or NO_x emission controls and SO_2 pollutant concentration monitors and/or NO_x continuous emission monitoring systems at the inlet and outlet of the emission control system may apply to the Administrator for approval and certification of a parametric, empirical, or process simulation method or model for calculating substitute data for missing data periods. Such methods may be used to parametrically estimate the removal efficiency of the SO_2 of postcombustion NO_x emission controls which, with the monitored inlet concentration or emission rate data, may be used to estimate the average concentration of SO_2 emissions or average emission rate of NO_x discharged to the atmosphere. After approval by the Administrator, such method or model may be used to for filling in missing SO_2 concentration or NO_x emission rate data when data from the outlet SO_2 pollutant concentration monitor or outlet NO_x continuous emission monitoring system have been reported with an annual monitor data availability of 90.0 percent or more.

Base the empirical and process simulation methods or models on the fundamental chemistry and engineering principles involved in the treatment of pollutant gas. On a case-by-case basis, the Administrator may pre-certify commercially available process simulation methods and models.

1.2 Demonstration Requirements

Continuously monitor, determine, and record hourly averages for the parameters specified below, at a minimum. The affected facility shall supply additional parametric information where appropriate. At least 4 evenly spaced data points are required for a valid hourly average, except during periods of calibration, maintenance, or quality assurance activities, during which 2 data points per hour are sufficient. The Administrator will review all applications on a case-by-case basis.

1.2.1 Parameters for Wet Flue Gas Desulfurization System

1.2.1.1 Number of scrubber modules in operation.

1.2.1.2 Total slurry rate to each scrubber module (gal per min).

1.2.1.3 In-line absorber pH of each scrubber module.

1.2.1.4 Pressure differential across each scrubber module (inches of water column).

1.2.1.5 Unit load (MWe).

1.2.1.6 Inlet and outlet SO_2 concentration as determined by the monitor or missing data substitution procedures.

1.2.1.7 Percent solids in slurry for each scrubber module.

1.2.1.8 Any other parameters necessary to verify scrubber removal efficiency, if the Administrator determines the parameters above are not sufficient.

1.2.2 Parameters for Dry Flue Gas Desulfurization System

1.2.2.1 Number of scrubber modules in operation.

1.2.2.2 Atomizer slurry flow rate to each scrubber module (gal per min).

1.2.2.3 Inlet and outlet temperature for each scrubber module (°F).

1.2.2.4 Pressure differential across each scrubber module (inches of water column).

1.2.2.5 Unit load (MWe).

1.2.2.6 Inlet and outlet SO_2 concentration as determined by the monitor or missing data substitution procedures.

1.2.2.7 Any other parameters necessary to verify scrubber removal efficiency, if the Administrator determines the parameters above are not sufficient.

1.2.3 Parameters for Other Flue Gas Desulfurization Systems

If SO_2 control technologies other than wet or dry lime or limestone scrubbing are selected for flue gas desulfurization, a corresponding empirical correlation or process simulation parametric method using appropriate parameters may be developed by the owner or operator of the affected unit, and then reviewed and approved or modified by the Administrator on a case-by-case basis.

1.2.4 Parameters for Post-Combustion NO_x Emission Controls

1.2.4.1 Inlet air flow rate to the unit (boiler) (mcf/hr).

1.2.4.2 Excess oxygen concentration of flue gas at stack outlet (percent).

1.2.4.3 Carbon monoxide concentration of flue gas at stack outlet (ppm).

1.2.4.4 Temperature of flue gas at outlet of the unit (°F).

1.2.4.5 Inlet and outlet NO_x emission rate as determined by the NO_x continuous emission monitoring system or missing data substitution procedures.

1.2.4.6 Any other parameters specific to the emission reduction process necessary to verify the NO_x control removal efficiency, (e.g., reagent feedrate in gal/mi).

emission monitoring system or missing data substitution procedures.

1.2.4.6 Any other parameters specific to the emission reduction process necessary to verify the NO_x control removal efficiency, (e.g., reagent feedrate in gal/mi).

1.3 Correlation of Emissions With Parameters

Establish a method for correlating hourly averages of the parameters identified above with the percent removal efficiency of the SO_2 or post-combustion NO_x emission controls under varying unit operating loads. Equations 1–7 in § 75.15 of this part may be used to estimate the percent removal efficiency of the SO_2 emission controls.

Each parametric data substitution procedure should develop a data correlation procedure to verify the performance of the SO_2 emission controls or post-combustion NO_x emission controls, along with the SO_2 pollutant concentration monitor and NO_x continuous emission monitoring system values for varying unit load ranges.

For NO_x emission rate data, and wherever the performance of the emission controls varies with the load, use the load range procedure provided in section 2.2 of this appendix.

1.4 Calculations

1.4.1 Use the following equation to calculate substitute data for filling in missing (outlet) SO_2 pollutant concentration monitor data.

$M_o = I_c (1–E)$

(Eq. C–1)

where,

M_o = Substitute data for outlet SO_2 concentration, ppm.

I_c = Recorded inlet SO_2 concentration, ppm.

E = Removal efficiency of SO_2 emission controls as determined by the correlation procedure described in section 1.2 of this appendix.

1.4.2 Use the following equation to calculate substitute data for filling in missing (outlet) NO_x emission rate data.

$M_o = I_c (1–E)$

(Eq. C–2)

where,

M_o = Substitute data for outlet NO_x emission rate, lb/mmBtu.

I_c = Recorded inlet NO_x emission rate, lb/mmBtu.

E = Removal efficiency of post-combustion NO_x emission controls determined by the correlation procedure described in section 1.2 of this appendix.

1.5 Missing Data

1.5.1 If both the inlet and the outlet SO_2 pollutant concentration monitors are unavailable simultaneously, use the maximum inlet SO_2 concentration recorded by the inlet SO_2 pollutant concentration monitor during the previous 720 quality assured monitor operating hours to substitute for the inlet SO_2 concentration in Equation C–1 of this appendix.

1.5.2 If both the inlet and outlet NO_x continuous emission monitoring systems are unavailable simultaneously, use the maximum inlet NO_x emission rate for the corresponding unit load recorded by the NO_x continuous emission monitoring system at the inlet during the previous 2160 quality assured monitor operating hours to substitute for the inlet NO_x emission rate in Equation C–2 of this Appendix.

1.6 Application

Apply to the Administrator for approval and certification of the parametric substitution procedure for filling in missing SO_2 concentration or NO_x emission rate data using the established criteria and information identified above. DO not use this procedure until approved by the Administrator.

2. Load-Based Procedure for Missing Flow Rate and NO_x Emission Rate Data

2.1 Applicability

This procedure is applicable for data from all affected units for use in accordance with the provisions of this part to provide substitute data for volumetric flow (scfh) and NO_x emission rate (in lb/mmBtu).

2.2 Procedure

2.2.1 For a single unit, establish 10 operating load ranges defined in terms of percent of the maximum integrated hourly gross load of the unit, in gross megawatts (MWge), (that is, load resulting from all combustion of fuel, including internal usage and generation for sale) as shown in Table C–1. For units sharing a common stack monitored with a single flow monitor, the load ranges for flow may be broken down into 20 equally-sized operating load ranges in increments of 5 percent of the combined maximum integrated hourly gross load of all units utilizing the common stack. For a cogenerating unit or other unit that does not produce electricity only from heat input, use the hourly gross steam load of the unit, in pounds of steam per hour at the measured temperature (°F) and pressure (psia) instead of MWge. Indicate a change in the number of load ranges or the units of loads to be used in the precertification section of the monitoring plan.

TABLE C–1.—DEFINITION OF OPERATING LOAN RANGES FOR LOAD-BASED SUBSTITUTION DATA PROCEDURES

Operating load range	Percent of maximum integrated hourly gross load (%)
1	0–10
2	>10–20
3	>20–30
4	>30–40
5	>40–50
6	>50–60
7	>60–70
8	>70–80
9	>80–90
10	>90–100

2.2.2 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_x continuous emission monitoring system, for each hour of unit operation record a number, 1 through 10, (or 1 through 20 for flow at common stacks) that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour.

2.2.3 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_x continuous emission monitoring system and continuing thereafter, calculate and record the following information for each unit operating hour within each identified load range during the shorter of: (1) the previous 2,160 quality assured monitor operating hours (on a rolling basis), or (2) all previous quality assured monitor operating hours.

2.2.3.1 A running average of the hourly flow rates reported by a flow monitor, in scfh, for all unit operating hours.

2.2.3.2 The 90th percentile value of hourly flow rates, in scfh.

2.2.3.3 The 95th percentile value of hourly flow rates, in scfh.

2.2.3.4 The maximum value of hourly flow rates, in scfh.

2.2.3.5 A running average of the hourly NO_x emission rate, in lb/mmBtu, reported by a NO_x continuous emission monitoring system for all unit operating hours.

2.2.3.6 The 90th percentile value of hourly NO_x emission rates, in lb/mmBtu.

2.2.3.7 The 95th percentile value of hourly NO_x emission rates, in lb/mmBtu.

2.2.3.8 The maximum value of hourly NO_x emission rates, in lb/mmBtu.

2.2.4 Calculate all monitor or continuous emission monitoring system data averages, maximum values, and percentile values determined by this procedure using bias adjusted values in the load ranges.

2.2.5 When a bias adjustment is necessary for the flow monitor and/or the NO_x continuous emission monitoring system, apply the adjustment factor to all monitor or continuous emission monitoring system data averages, maximum values, and percentile values determined by the procedure.

2.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO_x emission rate data according to the procedures in subpart D of this part.

Appendix D to part 75—Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units

1. Applicability

1.1 This procedure may be used in lieu of continuous SO_2 pollutant concentration and flow monitors for the purpose of determining hourly SO_2 emissions from: (1) Gas-fired units as defined in § 72.2 of this chapter; or (2) oil-fired units as defined in § 72.2 of this chapter. This optional SO_2 emissions data protocol contains two methods for conducting oil sampling and analysis in Section 2.2 of this appendix; the procedures for flow proportional oil sampling and the procedures for manual daily oil sampling may be used for any gas-fired unit or oil-fired unit.

1.2 This procedure may also be certified by the Administrator and used in lieu of continuous SO_2 pollutant concentration and flow monitors for the purpose of determining hourly SO_2 emissions from new gas-fired units or new oil-fired units provided that the new gas-fired unit or oil-fired unit is

designed to combust only oil, natural gas, or a coal-derived gaseous fuel with a sulfur content no greater than natural gas.

1.3 Apply to the Administrator for certification using this method in lieu of continuous SO_2 pollutant concentration and flow monitors no later than the deadlines for the certification of continuous emission monitoring system specified in § 75.4 of this part. Whenever the monitoring method is to be changed, reapply to the Administrator for certification of the new monitoring method.

1.4 Do not use the methods specified in this appendix for accounting for SO_2 emissions prior to obtaining certification from the Administrator.

2. Procedure

2.1 Flowmeter Measurements

When the unit is combusting oil, measure and record the flow of oil consumed on an hourly basis. Measure the flow of oil with an in-line fuel flowmeter and automatically record the data. Measure the flow of all oil entering and being combusted by the unit. Any pipe returning fuel to a pipe that provides oil to the unit (e.g. a pipe recirculating oil to the storage tank) requires an in-line fuel flowmeter.

2.1.1 Design and equip each fuel flowmeter used to meet the requirements of this protocol to demonstrate a flowmeter accuracy of 2.0 percent of the upper range value (i.e, maximum calibrated oil flow rate) as measured under laboratory conditions by the manufacturer or by the owner or operator. Use the procedures in the following ASME codes for flow measurement for use in the laboratory, as appropriate to the type of flow meter: ASME MFC–3M–1989 with September 1990 Errata (Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi), ASME MFC–5M–1985 (Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters), ASME MFC–6M–1987 with June 1987 Errata (Measurement of Fluid Flow in Pipes Using Vortex Flow Meters), or ASME MFC–9M–1988 with December 1989 Errata (Measurement of Liquid Flow in Closed Conduits by Weighing Method) for all other flow meter types (incorporated by reference under § 75.6 of this part). If the flow meter accuracy exceeds 2 percent of the upper range value, the flow meter does not qualify for certification.

2.1.2 Recalibrate each fuel flowmeter to a flowmeter accuracy of 2.0 percent of the upper range value at least annually, or more frequently if required by manufacturer specifications using the same ASME procedures required for initial calibration and certification, to meet the requirements of this protocol.

2.1.3 Alternatively, the fuel flowmeter used for the purposes of this part may be recalibrated to a flowmeter accuracy of 2.0 percent of the upper range value at least annually by comparing the measured flow of a flow meter to the measured flow from another flow meter which has been calibrated or recalibrated during the previous 365 days using the procedures in ASME MFC–9M–1988 with December 1989 Errata, "Measurement of Liquid Flow in Closed Conduits by Weighing Method", or which has been recalibrated by the manufacturer. Perform the comparison over a period of no more than seven consecutive unit operating days. Compare the average of three fuel flow readings for each meter at each of three different flow levels, corresponding to the three operating levels listed in § 6.5.2 of Appendix A of this part. Calculate the flowmeter accuracy using [Equation A–7 in Appendix A of this part, substituting the measured flow from the flow meter that is calibrated by the weighing method for the reference value.] Or the following equation:

$$ACC = \frac{|R-A|}{URV} \times 100$$

(Eq. D–1)

where,

ACC = Flow meter accuracy as a percentage of the upper range value.

R = Average of the three low-, mid-, or high-level flow measurements of the reference flow meter.

A = Average of the three measurements of the flow meter being tested.

URV = Upper range value of fuel flow meter being tested (i.e. maximum measurable flow).

If the flow meter accuracy exceeds 2% of the upper range value, either recalibrate the flow meter until the accuracy is within the performance specification, or replace the flow meter with another one that is within the performance specification.

2.2 Oil Sampling and Analysis

Perform sampling and analysis of as-fired oil to determine the percentage of sulfur by weight in the oil.

2.2.1 Perform oil sampling every day the unit is combusting oil. Use either the flow proportional method described in section 2.2.2 of this appendix or the daily manual method described in section 2.2.3 of this appendix for gas-fired units and oil-fired units.

2.2.2 Conduct flow proportional oil sampling or continuous drip oil sampling in accordance with ASTM D4177–82 (Reapproved 1990), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.6 of this part), every day the unit is combusting oil. Extract oil at least once every hour and blend into a daily composite sample. The sample compositing period may not exceed 24 hr.

2.2.3 For a gas-fired unit or oil-fired unit, representative as-fired oil samples may be taken manually every 24 hr according to ASTM D4057–88, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.6 of this part), provided that the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples is used for the purposes of calculating SO_2 emissions under Section 3 of this appendix.

Note: For units with pressurized fuel flow lines such as some diesel and dual-fuel reciprocating internal combustion engine units, a manual sample may be taken from the point closest to the unit where it is safe to take a sample (including back to the oil tank), rather than just prior to entry to the boiler or combustion chamber.

2.2.4 Split and label each daily oil sample. Maintain a portion (at least 200 cc) of each daily sample throughout the calendar year and in all cases for not less than 90 calendar days after the end of the calendar year allowance accounting period. Analyze oil samples for percent sulfur content by weight in accordance with ASTM D129–91, "Standard Test Method for Sulfur in Petroleum Products (General Bomb Method)," ASTM D1552–90, "Standard Test Method for Sulfur in Petroleum Products (High Temperature Method)," ASTM D2622–92, "Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry," or ASTM D4294–90, "Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy" (incorporated by reference under § 75.6).

2.2.5 Where the flowmeter records volumetric flow rather than mass flow, analyze daily oil samples to determine the density or specific gravity of the oil. Determine the density or specific gravity of the oil sample in accordance with ASTM D941–88, "Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Lipkin Bicapillary Pycnometer," ASTM D1217–91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer," ASTM D1481–91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary," ASTM D1480–91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer," ASTM D1298–85 (Reapproved 1990), "Standard Practice for Density, Relative Density (Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method," or ASTM D4052–91, "Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter" (incorporated by reference under § 75.6).

2.2.6 Analyze daily oil samples to determine the heat content of the fuel. Determine oil heat content in accordance with ASTM D240–87 (1Reapproved 1991), "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter," ASTM D1382–88, "Standard Test Method for Heat or Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method)", or ASTM D2015–91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter" (incorporated by reference under § 75.6).

2.2.7 Results from the daily oil sample analysis must be available no later than thirty calendar days after the same is composited or taken. However, during an audit, the Administrator may require the results of the analysis in less than thirty calendar days.

2.3 *Missing Data Procedures.*

When data from the procedures of this part are not available, provide substitute data using the following procedures.

2.3.1 When sulfur content data from the analysis of a daily oil sample are missing or

invalid, substitute the highest measured sulfur content and oil density (if using a volumetric flowmeter) recorded during the previous 30 days when the unit burned oil.

2.3.2 When data from the fuel flowmeter are missing, substitute for each hour in the missing data period the average hourly oil flow rate measured and recorded by the fuel flowmeter at the closet unit load (in MWe) greater than the load recorded for the missing data period for which oil flow rate data are available during the previous 720 hours during which the unit combusted oil. If no oil flow rate data are available at a load greater than the load recorded during the missing data period, substitute the maximum flow rate that the flowmeter can measure.

2.4 For each hour that natural gas is combusted by the unit, account for the daily SO_2 emissions, either by (1) measuring the sulfur content of the gas using ASTM D1072–90, "Standard Test Method for Total Sulfur in Fuel Gases" (incorporated by reference under § 75.6 of this part) and the fuel usage in 100 scf or (2) using the SO_2 emission rates listed in NADB for that unit and the daily heat input from natural gas, as determined using the procedures in Appendix F of this part.

3. Calculations

Where the flowmeter records mass flow, use the calculation procedures in section 3.1, and where the flowmeter records volumetric flow, use the calculation procedures in section 3.2.

3.1 SO_2 Calculation Using Mass Flow

3.1.1 Use the following equation to calculate SO_2 mass emissions per hour (in lb/hr).

$M_{so2}=2.0\times M_{oil}\times \%S_{oil}/100.0$
(Eq. D–1)

where,
M_{so2}=Hourly mass of SO_2 emitted, lb/hr.
M_{oil}=Mass of oil consumed per hr, lb/hr.
$\%S_{oil}$=Percentage of sulfur by weight measured in the sample.
2.0=Ratio of lb SO_2/lb S.

3.1.2 Record the SO_2 mass emissions for each hour. Calculate and record total quarterly and annual SO_2 mass emissions by summing hourly SO_2 mass emissions for each hour during that quarter or year when the unit combusted any oil.

3.2 SO_2 Calculation Using Volumetric Flow

3.2.1 Where the flowmeter records volumetric flow rather than mass flow, calculate and record the oil mass for each hourly period using hourly oil flow measurements and the density or specific gravity of the daily oil sample.

3.2.2 Convert density, specific gravity, or API gravity of the oil sample to density of the oil sample at the sampling location's temperature using ASTM D1250–80 (Reapproved 1990), "Standard Guide for Petroleum Measurement Tables" (incorporated by reference under § 75.6 of this part).

3.2.3 Where density of the oil is determined by the applicable ASTM procedures from section 2.2.5 of this appendix, use the following equation to calculate the mass of oil consumed (in lb/hr).

$M_{oil}=V_{oil}\times D_{oil}$
(Eq. D–2)

where,
M_{oil}=Mass of oil consumed per hr, lb/hr.
V_{oil}=Volume of oil consumed per hr, measured in scf, gal, barrels, or m^3.
D_{oil}=Density of oil, measured in lb/scf, lb/gal, lb/barrel, or lb/m^3.

3.2.4 Calculate the hourly heat input to the unit from oil (mmBtu) by multiplying the heat content of the daily oil sample by the hourly oil mass.

Appendix E to Part 75—Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units

1. Applicability.

1.1 Existing Unit

This NO_x emissions estimation procedure may be used in lieu of a continuous NO_x emission monitoring system (lb/mmBtu) for determining the average NO_x emission rate and hourly NO_x emission rate from gas-fired peaking units and oil-fired peaking units when these units are (1) operated with a capacity factor of 10 percent or less on the average during the previous three calendar years and (2) operated at a capacity factor of 20 percent or less in each of those three previous calendar years. If for any year a unit's operations exceed a capacity factor of 20 percent, or if a unit's operations exceed an average capacity factor of 10 percent over the most recent three calendar years, install and certify a continuous NO_x emission monitoring system no later than December 31 of the following calendar year.

1.2 New Unit

For a new gas-fired peaking unit or a new oil-fired peaking unit commencing commercial operation after November 15, 1990 where the projected capacity factor is 10 percent or less when averaged over 3 consecutive calendar years, this procedure may be certified and used in lieu of a continuous NO_x emission monitoring system. If the new gas-fired peaking unit or the new oil-fired peaking unit operating rate is greater than 20 percent in any one calendar year or greater than 10 percent on the average for any 3 consecutive calendar years, install and certify a continuous NO_x emission monitoring system on or before December 31 of the following calendar year.

1.3 Certification

1.3.1 Apply to the Administrator for certification of this optional method no later than the deadlines for the installation of continuous emission monitoring systems specified in § 75.4 of this part.

1.3.2 Do not use this optional method to record or report NO_x emissions prior to obtaining certification from the Administrator.

2. Procedure

2.1 Initial Performance Testing

Use the following procedures for measuring NO_x emission rates at different load levels; measuring unit efficiency and heat input; and plotting the correlation between operating load and NO_x emission rate or unit efficiency, in order to determine the performance and emission rate of the unit(s) prior to certification of this optional method.

2.1.1 Load Selection

Establish five approximately equally spaced operating load points, ranging from the maximum operating load to the minimum operating load. Use the unit's nameplate capacity as the maximum operating load. Select the minimum operating load from the operating history of the unit during the most recent two years. For new gas-fired peaking units or new oil-fired peaking units, select the minimum operating load from the expected minimum load to be dispatched to the unit in the first three calendar years of operation.

2.1.2 NO_x and O_2 Concentration Measurements

Use the following procedures to measure NO_x and O_2 concentration in order to determine NO_x emission rate.

2.1.2.1 Except for stationary gas turbines, measure the NO_x and O_2 concentration at 3 excess oxygen levels at each load point for each fuel or each combination of fuels to be combusted using the methods specified below in section 2.1.2.2 or 2.1.2.3 of this appendix. Establish the three excess oxygen levels as the minimum, normal, and maximum levels. Select the minimum, normal, and maximum levels at each load point according to the operating history of the unit during the most recent two years. For new gas-fired peaking units or new oil-fired peaking units, select the minimum, normal, and maximum levels at each load point per manufacturer's recommendations. For stationary gas turbines, measure the NO_x and O_2 concentration at the normal oxygen level at each load, and again at another oxygen level if the temperature of the (combustion) air at the air intake varies by more than 4°F from the average test conditions at that load.

2.1.2.2 Measure the NO_x and O_2 concentrations according to Appendix A, Method 20 of part 60 of this chapter for stationary gas turbines. Measure the NO_x and O_2 concentrations according to Method 20 for diesel or dual fuel fuel reciprocating engines, but modify Method 20 with respect to the selection of a sampling site to be as close as practical to the exhaust of the engine.

2.1.2.3 Measure the NO_x and O_2 concentrations according to Appendix A, Methods 7E of 3A of part 60 of this chapter for all other gas-fired peaking units or oil-fired peaking units.

2.1.2.4 Allow the unit to stabilize for a minimum of one hour prior to commencing NO_x, O_2, and unit efficiency measurements. Repeat the NO_x measurement two times (i.e., for a total of three times) and obtain an arithmetic average of the NO_x measurements for each of the three oxygen levels. Record the oxygen level for a period of at least 20 minutes at 5 minute intervals and report the average of all readings as the excess oxygen level for this period.

2.1.3 Heat Input

Measure the total heat input of fuel flow or a combination of fuel flows as follows:

2.1.3.1 Calibrate in-line flow meters using the procedures and specifications contained in the following ASME codes for flow measurement for use in the laboratory, as appropriate to the type of flow meter: ASME MFC–3M–1989 with September 1990 Errata (Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi), ASME MFC–4M–1986 (Reaffirmed 1990) (Measurement of Gas Flow by Turbine Meters, ASME MFC–5M–1985 (Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters), ASME MFC–6M–1987 with June 1987 Errata (Measurement of Fluid Flow in Pipes Using Vortex Flow Meters), ASME MFC–7N–1987 (Reaffirmed 1992) (Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles), ASME MFC–9M–1988 with December 1989 Errata (Measurement of Liquid Flow in Closed Conduits by Weighing Method for other flow meter types for liquids) (incorporated by reference under § 75.6 of this part), or any other standard method approved by the Administrator. Measure the total consumption of the fuels with in-line flow meters for a period of 15 minutes. Correct any gaseous fuel flow rate measured at actual temperature and pressure to standard conditions.

2.1.3.2 For liquid fuels, analyze daily fuel samples to determine the heat content of the fuel. Determine heat content in accordance with ASTM D240–87 (Reapproved 1991) "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter," ASTM D2382–88, "Standard Test Method for Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method)" or ASTM D2015–91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter" (incorporated by reference under § 75.6 of this part). Measure the heat content of gaseous fuels according to ASTM D1826–88, "Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter". Calculate the total heat input using Equation E–1 of this appendix. Record the total heat input of fuel flow or a combination of fuel flows for each excess oxygen level at each load point.

2.1.4 Unit Efficiency

Use the following procedures to measure unit efficiency.

2.1.4.1 Measure the unit efficiency of the stationary gas turbine, the diesel, or the dual fuel-reciprocating engine at the same excess oxygen levels as established in section 2.1.2.1 of this appendix at each load point for each fuel or combination of fuels to be combusted according to one of the following methods. Use the same method for subsequent periodic retesting of the initial unit efficiency correlations.

2.1.4.2 Measure the fuel consumption, the total heat input of fuel flow or combination of fuel flows to the stationary gas turbine, and the electric energy output of the stationary gas turbine for a period of 15 minutes using the procedures specified in the ASME Performance Test Code (PTC) 22–1985, Gas Turbine Power Plants (incorporated by reference under § 75.6 of this part). Correct any gaseous fuel flow rate measured at actual temperature and pressure to standard conditions (68°F and 29.92 inches of mercury). Measure the fuel consumption, the total heat input of fuel flow or combination of fuel flows, and the electric energy output of the diesel or dual-fuel reciprocating engine for a period of 15 minutes using the procedures specified in the ASME Performance Test Code 17–1973 (Reaffirmed 1991), Reciprocating Internal-Combustion Engines (incorporated by reference under § 75.6 of this part). Compute the unit efficiency of the reciprocating engines using Equation E–2 of this appendix.

2.1.4.3 Measure the unit efficiency of all other oil- or gas-fired units at the same excess oxygen levels as established in section 2.1.2 of this appendix using the Heat Loss Method contained in the ASME Power Test Code 4.1–1964 (Reaffirmed 1991), Steam Generating Units (incorporated by reference under § 75.6 of this part). Compute the unit efficiency of the gas-fired peaking unit or oil-fired peaking unit using Equation E–2 of this appendix.

2.1.4.4 Allow the unit to stabilize for a minimum of one hour prior to commencing NO_x, O_2, and unit efficiency measurements. Repeat the NO_x measurement two times (i.e. for a total of three times) and obtain an arithmetic average of the NO_x measurements for each of the three oxygen levels. Record the oxygen level for a period of at least 20 minutes at 5 minute intervals and report the average of all readings as the excess oxygen level for this period.

2.1.5 Tabulation of Results

Tabulate the results of each baseline correlation test for each fuel or combination of fuels, listing: time of test, duration, operating loads, F-factors, excess oxygen levels, NO_x concentrations (ppm) on a dry basis (at actual excess oxygen level), and unit efficiency. Convert the NO_x concentrations (ppm) to NO_x emission rates (to the nearest 0.01 lb/mmBtu) according to the equation E–3 or E–4, as appropriate, of this appendix.

2.1.6 Plotting of Results

Plot the tabulated results as an x-y graph for each fuel or combination of fuel to be combusted according to the following procedures.

2.1.6.1 Plot the operating load as the independent (or x) variable and the NO_x emission rates (lb/mmBtu) as the dependent (or y) variable, where three values corresponding to the three excess oxygen levels are established according to section 2.1.2.1 of this appendix for each load point. Construct the graph by drawing four straight line segments between the five load points by connecting the highest NO_x concentration at each load point.

2.1.6.2 Plot the operating load as the independent (or x) variable and the unit efficiency as the dependent (or y) variable, where three values corresponding to the three excess oxygen levels are established according to section 2.1.2.1 of this appendix for each load point. Construct the graph by drawing four straight line segments between the five load points by connecting the unit efficiency corresponding to the nominal oxygen level at each load point.

2.2 Periodic NO_x Emission Rate Testing

Retest the NO_x emission rate of the gas-fired peaking unit or the oil-fired peaking unit prior to the earlier of 3,000 unit operating hours or the 5-year anniversary and renewal of its operating permit under part 72 of this chapter.

2.3 Other Quality Assurance/Quality Control-Related NO_x Emission Rate Testing

When the operating levels of certain parameters exceed the limits specified below, retest the NO_x emission rate to re-verify the gas-fired peaking unit's or the oil-fired peaking unit's NO_x emission rate.

2.3.1 For a stationary gas turbine, redetermine the NO_x emission rate-load correlation for each fuel and combination of fuels after exceeding the manufacturer's recommended range of the following operating parameters: positioning of inlet guide vanes (i.e., degrees of rotation of inlet guide vanes), amount of air bypass used for turbine blade cooling, flow rate of steam or water injection used for NO_x emission control, exhaust temperature, compression ratio, ambient air temperature and pressure, inlet oxygen temperature and press (if stored oxygen or on-site oxygen plant is used), unit efficiency (or unit heat rate), and any other parameters specified by the unit manufacturer.

2.3.2 For a diesel or a dual-fuel reciprocating engine, redetermine the NO_x emission rate-load correlation for each fuel or combination of fuels after exceeding the manufacturer's recommended range of the following operating parameters: air intake manifold temperature, air intake manifold pressure, exhaust temperature, compression ratio, piston speed, brake mean effective pressure, supercharging, turbocharging, unit efficiency (or unit heat rate), and any other parameters specified by the unit manufacturer.

2.3.3 For all other gas-fired peaking units and oil-fired peaking units, redetermine the NO_x emission rate load correlation for each fuel and combination of fuels if any of the following occurs:

2.3.3.1 The heat input rate (mmBtu/hr) at either the maximum or the minimum operating load varies by more than 10 percent from the heat input rate at the maximum or the minimum operating load during the previous NO_x emission rate test; or

2.3.3.2 The excess oxygen level at either the maximum or the minimum operating load varies by more than 2 percentage points O_2 from the level during the maximum or minimum operating load during the previous NO_x emission rate test; or

2.3.3.3 The unit efficiency at nominal excess O_2 at either the maximum or the minimum operating load varies by more than 3 percentage points from the unit efficiency during the maximum operating load of the previous unit efficiency test, as defined using Equation E–2 of this appendix.

2.4 Procedures for Determining Hourly NO_x Emission Rate

2.4.1 Record the time (hr. and min.) and electric energy output (MWh) at the beginning of each time period, with each time period as close to one hour in duration as practical. Calculate the average operating load using equation E–8 of this appendix.

Record this average operating load to the nearest 0.1 MW as the reading for the beginning of the time period, time t. Record the next average operating load to the nearest 0.1 MW as the reading for the end of the first time period, time t+1, and so on.

2.4.2 Read the NO_x emission rate (lb/mmBtu) corresponding to the appropriate operating load, linearly interpolating to the nearest 0.1 MW and 0.01 lb/mmBtu, using the tabulated results of the baseline NO_x correlation appropriate to the fuel or fuel combination being combusted. Record the NO_x emission rate (to the nearest 0.01 lb/mmBtu) at the beginning of each time period.

2.5 Missing Data

Provide substitute data for each unit electing to use this alternative procedure whenever a valid quality-assured hour of NO_x emission rate data has not been obtained according to the procedures and specifications of section 2.4 of this appendix. For all missing data, substitute the highest NO_x emission rate tabulated during the most recent set of baseline correlation tests for any fuel or combination of fuels at the observed operating load. Maintain a record indicating which data are substitute data and the reasons for the failure to provide a valid quality-assured hour of NO_x emission rate data according to the procedures and specifications of section 2.4 of this appendix.

3. Calculations

3.1 Heat Input

Calculate the total heat input by summing over the product of fuel consumption and the measured heat control of each fuel, as in the following equation:

$$H_T = \sum_{f=1}^{n} \sum_{t=1}^{T} 10^{-6} Q_{ft} H_f t$$

(Eq. E–1)

where

H_T=total heat input of fuel flow or a combination of fuel flows over a total time of T hours, mmBtu;

10^{-6}=conversion of Btu to mmBtu;

H_f=heat content of each fuel, Btu/scf, Btu/lb, or other appropriate units;

Q_{ft}=flow rate measured for each fuel at time t (and corrected to 68°F and 29.92 inches of mercury if fuel is gaseous), scfh, lb/hr, or other appropriate units;

n=total number of fuels to be combusted;

T=total number of hours during which heat input is computed.

3.2 Unit Efficiency

Compute unit efficiency according to the following equation:

$$\eta = \frac{(100)\ (3412)\ E}{H\ 10^6}$$

(Eq. E–2)

where,

η=unit efficiency, percent;

100=factor to convert to percentage;

10^6=conversion of mmBtu to Btu;

E=total electric energy output (kilowatt-hour) for a specified interval of time, kWh;

3412=factor to convert kwh to Btu;

H=total heat input of fuel flow for the same specified interval of time as in E, mmBtu.

3.3 F-factors

Compute the F-factors for each fuel or combination of fuels to be combusted according to Appendix A, Method 19, sections 3.2.1–3.2.4 and section 3.3 of part 60 of this chapter. For a combination of fuels, use Eq. F–8 in Appendix F of this part, using the F-factors computed above for each fuel.

3.4 NO_x Emission Rate

3.4.1 Conversion from Concentration to Emission Rate

Convert the NO_x concentrations (ppm) to NO_x emission rates (to the nearest 0.01 lb/mmBtu) according to the appropriate one of the following equations:

$$E = K\ C_d\ F_d\ \frac{20.9}{20.9 - \%O2}$$

(Eq. E–3)

where,

E=NO_x emission rate, lb/mmBtu;

K=1.19×10^{-7} (lb/dscf)/ppm NO_x

C_d=NO_x concentration measured, dry basis, ppm;

F_d=dry basis F-factor computed in Section 3.3 of this appendix, dscf/mmBtu;

20.9=percentage of air that is oxygen, percent;

$\%O_2$=O_2 concentration measured, dry basis, %.

or

$$E = K\ C_w\ F_d\ \frac{20.9}{[(20.9/100)\ (100 - \%H_2O)\ - \%O_{2w}]}$$

(Eq. E–4)

where,

E=NO_x emission rate, lb/mmBtu;

K=1.19×10^{-7} (lb/dscf)/ppm NO_x

C_w=NO_x concentration measured, wet basis, ppm;

F_d=dry basis F-factor computed in Section 3.3 of this appendix, dscf/mmBtu;

20.9=percentage of air that is oxygen, percent;

$\%H_2O$=moisture content of sample gas as measured by Appendix A, Method 4, of part 60 of this chapter, percent.

$\%O_{2w}$=O_2 concentration measured, wet basis, %.

3.4.2 Quarterly Average NO_x Emission Rate

Report the quarterly average emission rate (lb/mmBtu) as required in subpart G of this part. Calculate the quarterly average NO_x emission rate according to the following equation:

$$E_q = \sum_{i=1}^{n} \frac{E_i}{n}\ \text{(Eq. E-5)}$$

where,

E_q=NO_x emission rate averaged over a quarter, lb/mmBtu;

E_i=hourly NO_x emission rate, lb/mmBtu;

n=number of hourly rates available in the preceding quarter.

3.4.3 Annual Average NO_x Emission Rate

Report the quarterly average emission rate (lb/mmBtu) as required in subpart G of this part. Calculate the annual average NO_x emission rate according to the following:

$$E_a = \sum_{i=1}^{n} \frac{E_i}{n}\ \text{(Eq. E-6)}$$

where,

E_a=NO_x emission rate averaged over the previous calendar year, lb/mmBtu;

E_i=hourly NO_x emission rate, lb/mmBtu;

n=number of hourly NO_x emission rates available in the preceding calendar year.

3.4.4 Cumulative NO_x Emission

Report the cumulative NO_x emissions (tons) as required in subpart G of this part. Calculate the cumulative NO_x emission rate according to the following equation:

$$E_{total} = \frac{E_a H_a}{2000}\ \text{(Eq. E-7)}$$

where,

E_{total}=cumulative NO_x emissions in the previous calendar year, tons;

E_a=NO_x emission rate averaged over the previous calendar year, lb/mmBtu;

H_a=total heat input in the previous calendar year, mmBtu.

3.5 Average Operating Load

Calculate the average operating load as follows:

$$P = \frac{E_{t+1} - E_t}{T}\ \text{(Eq. E-8)}$$

where,

P=average operating load (electric), MWe;

E_t=electric energy output (megawatt-hour) reading at the beginning of the time period, time t, MWh;

E_{t+1}=electric energy output (megawatt-hour) reading at the end of the time period, time t+1, MWh;

T=the duration of the time period from t to t+1, calculated by taking the difference between t+1 and t, hr.

4. Quality Assurance/Quality Control Plan

Include a section on the NO_x emission rate determination as part of the monitoring quality assurance/quality control plan required under § 75.21 and Appendix B of this part for each gas-fired peaking unit and each oil-fired peaking unit. In this section present information including, but not limited to, the following: (1) A copy of all data and results from the initial NO_x emission rate and unit efficiency testing, including the values of quality assurance parameters specified in Section 2.3 of this appendix; (2) a copy of all data and results from the most recent NO_x emission rate load correlation and unit efficiency testing; (3) a copy of the unit manufacturer's recommended range of quality assurance- and quality control-related operating parameters.

4.1 Submit a copy of the unit manufacturer's recommended range of operating parameter values, and the range of operating parameter values recorded during the previous NO_x emission rate test and unit efficiency test that determined the unit's NO_x emission rate, along with the unit's monitoring plan.

4.2 Keep records of these operating parameters for each hour of operation in order to demonstrate that a unit is remaining within the manufacturer's recommended operating range.

Appendix F to Part 75—Conversion Procedures

1. Applicability

Use the procedures in this appendix to convert measured data from a monitor or continuous emission monitoring system into the appropriate units of the standard.

2. Procedures for SO_2 emissions

Use the following procedures to compute hourly, quarterly, and annual SO_2 mass emissions (in lb/hr). Use the procedures in Method 19 in Appendix A to part 60 of this chapter to compute hourly SO_2 emission rates (in lb/mmBtu) for qualifying Phase I technologies.

2.1 When measurements of SO_2 concentration and flow rate are on a wet basis, use the following equation to compute hourly SO_2 mass emissions (in lb/hr).

$E_h = K\ C_h\ Q_h$

(Eq. F–1)

where,

E_h=Hourly SO_2 mass emissions, lb/hr.

K=1.660×10^{-7} for SO_2, (lb/scf)/ppm.

C_h=Hourly average SO_2 concentration, stack moisture basis, ppm.

Q_h=Hourly average volumetric flow rate, stack moisture basis, scfh.

2.2 When measurements by the SO_2 pollutant concentration monitor are on a dry basis and the flow rate monitor measurements are on a wet basis, use the following equation to compute hourly SO_2 mass emissions (in lb/hr).

$$E_h = K\ C_{hp}\ Q_{hs}\ \frac{(100 - \%H_2O)}{100}$$

(Eq. F–2)

where,

E_h=Hourly SO_2 mass emissions, lb/hr.

K=1.660×10^{-7} for SO_2, (lb/scf)/ppm.

C_{hp}=Hourly average SO_2 concentration, ppm (dry).

Q_{hs}=Hourly average volumetric flow rate, scfh as measured (wet).

$\%H_2O$=Hourly average stack moisture content, percent by volume.

2.3 Use the following equations to calculate total SO_2 mass emissions for each calendar quarter (Eq. F–3) and for each calendar year (Eq. F–4) in tons.

$$E_q = \frac{\sum_{h=1}^{n} E_h}{2000}$$

(Eq. F–3)

where,

E_q=Quarterly total SO_2 mass emissions, tons.

E_h=Hourly SO_2 mass emissions, lb/hr.

n=Number of hourly SO_2 emissions values during calendar quarter.

2000=Conversion of 2000 lb per ton.

$$E_a = \sum_{q=1}^{4} E_q$$

(Eq. F–4)

where,

E_a=Annual total SO_2 mass emissions, tons.

E_q=Quarterly SO_2 mass emissions, tons.

q=Quarters for which E_q are available during calendar year.

2.4 Round all SO_2 mass emissions to the number of decimal places identified in § 75.50(c) of this part (in lb/hr).

3. Procedures for NO_x Emission Rate

Use the following procedures to convert continuous emission monitoring system measurements of NO_x concentration (ppm) and diluent concentration (percentage) into NO_x emission rates (in lb/mmBtu). Perform measurements of NO_x and diluent (O_2 or CO_2) concentrations on the same moisture (wet or dry) basis.

3.1 When the NO_x continuous emission monitoring system uses O_2 as the diluent, and measurements are performed on a dry basis, use the following conversion procedure:

$$E = K\ C_h\ F\ \frac{20.9}{20.9 - \%O_2}$$

(Eq. F–5)

where,

K, E, C_h, F, and $\%O_2$ are defined in section 3.3 of this appendix. When measurements are performed on a wet basis, use the equations in Method 19 in Appendix A of part 60 of this chapter.

3.2 When the NO_x continuous emission monitoring system uses CO_2 as the diluent, use the following conversion procedure:

$$E = K\ C_h\ F_c\ \frac{100}{\%CO_2}$$

(Eq. F–6)

where,

K, E, C_h, F_c, and $\%CO_2$ are defined in section 3.3 of this appendix.

3.3 Use the definitions listed below to derive values for the parameters in Equations F–5 and F–6 of this appendix.

3.3.1 K=1.19×10^{-7} (lb/dscf)/ppm NO_x.

3.3.2 E=pollutant emissions, lb/mmBtu.

3.3.3 C_h=hourly average pollutant concentration, ppm.

3.3.4 $\%O_2$, $\%CO_2$=oxygen or carbon dioxide volume (expressed as percent O_2 or CO_2).

3.3.5 F, F_c=a factor representing a ratio of the volume of dry flue gases generated to the caloric value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Table 1 lists the values of F and F_c for different fuels.

TABLE 1.—F- AND F_c-FACTORS [1]

Fuel	F-factor (dscf/mmBtu)	F_c-factor (scf CO_2/mmBtu)
Coal (as defined by ASTM D388–92):		
Anthracite	10,100	1,970
Bituminous and subbituminous	9,780	1,800
Lignite	9,890	1,910
Oil	9,190	1,420
Gas:		
Natural gas	8,710	1,040
Propane	8,710	1,190
Butane	8,710	1,250
Wood:		
Bark	9,600	1,920
Wood residue	9,240	1,830

[1] Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.

3.3.6 Equations F–7a and F–7b may be used in lieu of the F or F_c factors specified in Section 3.3.5 of this appendix to calculate an F factor (dscf/mmBtu) on a dry basis or an F_c factor (scf CO_2/mmBtu) on either a dry or wet basis.

(Calculate all F- and F_c factors at standard conditions of 20 °C (68 °F) and 29.92 inches of mercury.)

$$F = \frac{3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)}{GCV} \times 10^6$$

(Eq. F–7a)

$$F_c = \frac{321 \times 10^3 (\%C)}{GCV}$$

(Eq. F–7b)

3.3.6.1 H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as the gross calorific value (GCV) by ultimate analysis of the fuel combusted using ASTM D3176–89, "Standard Practice for Ultimate Analysis of Coal and Coke" (solid fuels), or computed from results using ASTM D1945–91, "Standard Test Method for Analysis of Natural Gas by Gas Chromatography" or ASTM D1946–90, "Standard Practice for Analysis of Reformed Gas by Gas Chromatography" (gaseous fuels) as applicable. (These three methods are incorporated by reference under § 75.6 of this part.)

3.3.6.2 GCV is the gross calorific value (Btu/lb) of the fuel combusted determined by ASTM D2015–91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter" for solid and liquid fuels, and ASTM D1826–88, "Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter" for gaseous fuels, as applicable. (These two methods are incorporated by reference under § 75.6 of this part).

3.3.6.3 For affected units that combust a combination of fossil (coal, oil and gas) and nonfossil (e.g., bark, wood, residue, or refuse) fuels, the F or F_c value is subject to the Administrator's approval.

3.3.6.4 For affected units that combust combinations of fossil fuels or fossil fuels and wood residue, prorate the F or F_c factors determined by Section 3.3.5 of this appendix in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \qquad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

(Eq. F–8)

where,

X_i = Fraction of total heat input derived from each type of fuel (e.g., natural gas, bituminous coal, wood).

F_i or $(F_c)_i$ = Applicable F or F_c factor for each fuel type determined in accordance with Section 3.3.5 of this appendix.

n = Number of fuels being combusted in combination.

3.4 Use the following equations to calculate the average NO_x emission rate for each calendar quarter (Eq. F–9) and the annual average emission rate for each calendar year (Eq. F–10) in lb/mmBtu.

$$E_q = \sum_{i=1}^{n} \frac{E_i}{n}$$

(Eq. F–9)

where,

E_q = Quarterly average NO_x emission rate, lb/mmBtu.

E_i = Hourly average No_x emission rate, lb/mmBtu.

n = Number of hourly rates during calendar quarter.

$$E_a = \sum_{i=1}^{m} \frac{E_i}{m}$$

(Eq. F–10)

where,

E_a = Annual average No_x emission rate, lb/mmBtu.

E_i = Average hourly NO_x emission rate, lb/mmBtu.

m = Number of hours for which E_i is available in preceding calendar year.

3.5 Round all NO_x emission rates to the nearest 0.01 lb/mmBtu.

4. Procedures for CO_2 Mass Emissions

Use the following procedures to convert continuous emission monitoring system measurements of CO_2 concentration (percentage) and volumetric flow rate (scfh) into CO_2 mass emissions (in tons/day) when the owner or operator uses a CO_2 continuous emission monitoring system (consisting of a CO_2 diluent gas monitor and a flow monitor) to monitor CO_2 emissions from an affected unit.

4.1 When CO_2 concentration is measured on a wet basis, use the following equation to calculate hourly CO_2 mass emissions rates (in tons/hr).

$E_h = K C_h Q_h$

(Eq. F–11)

where,

E_h = Hourly CO_2 mass emissions, tons/hr.

$K = 5.7 \times 10^{-7}$ for CO_2, (tons/scf) /$\%CO_2$.

C_h = Hourly average CO_2 concentration, stack moisture basis, $\%CO_2$.

Q_h = Hourly average volumetric flow rate, stack moisture basis, scfh.

4.2 When CO_2 concentration is measured on a dry basis, use Equation F–2 to calculate the hourly CO_2 mass emissions (in tons/hr) with a K-value of 5.7×10^{-7} (tons/scf)$\%CO_2$, where E_h = hourly CO_2 mass emissions, tons/hr and C_{wp} = hourly average CO_2 concentration in flue; dry basis, $\%CO_2$.

4.3 Use the following equations to calculate total CO_2 mass emissions for each calendar quarter (Equation F–12 and for each calendar year (Equation F–13).

$$E_{CO_{2q}} = \sum_{i=1}^{H_R} E_{h_i}$$

(Eq. F–12)

where,

E_{co2q} = Quarterly total CO_2 mass emissions, tons.

E_{hi} = Hourly CO_2 mass emissions (tons/hr).

H_R = Number of hourly CO_2 mass emsissions available during calendar quarter.

$$E_{CO_{2a}} = \sum_{q=1}^{4} E_{CO_{2q}}$$

(Eq. F–13)

where,

E_{CO2a}=Annual total CO_2 mass emissions, tons.

E_{CO2q}=Quarterly total CO_2 mass emissions, tons.

q=Quarters for which E_{CO2q} are available during calendar year.

4.3.1 Whenever a valid hour of CO_2 concentration data has not been obtained and recorded, substitute for each hour in each missing data period the average of the recorded CO_2 concentration for the hour immediately before and the hour immediately following the missing data period.

4.3.2 Whenever a valid hour of volumetric flow rate data has not been obtained and recorded, use the procedure specified in subpart D of this part to provide substitute data.

4.3.3 Whenever CO_2 mass emissions data have not been measured and recorded for a period of 72 consecutive unit operating hours or for at least 90 percent of the total unit operating hours during the calendar quarter, use the appropriate procedures in Appendix G to this part to estimate CO_2 mass emissions from the affected unit.

4.4 For an affected unit, when the owner or operator is continuously monitoring O_2 concentration (in percent by volume) of flue gases using a diluent O_2 monitor, use the equations and procedures in section 4.4.1–4.4.3 of this appendix to determine hourly CO_2 mass emissions (in tons).

4.4.1 Use appropriate F and F_c factors from section 3.3.5 of this appendix in the following equation to determine hourly average CO_2 concentration of flue gases (in percent by volume).

$$CO_{2h} = 100 \frac{F_c}{F} \frac{20.9 - O_{2h}}{20.9}$$

(Eq. F–14)

Where,

CO_{2h}=Hourly average CO_2 concentration, percent by volume, dry basis.

F, F_c=F-factor or carbon-based F_c-factor from Section 3.3.5 of this appendix.
20.9=percentage of O_2 in ambient air.
O_{2h}=Hourly average O_2 concentration, percent by volume, dry basis.Q02

4.4.2 Determine CO_2 mass emissions (in tons) from hourly average CO_2 concentration (percent by volume) using Equation F–11 and the procedures in Sections 4.1 and 4.2 of this appendix.

4.4.3 Whenever a valid hour of O_2 concentration data has not been obtained and recorded, use the procedures in Sections 4.3.1–4.3.3 of this appendix to provide substitute data for each hour of each missing data period except that the phrase "CO_2 concentration" is replaced with "O_2 concentration."

5. Procedures for Heat Input

Use the following procedures to compute heat input to an affected unit (in mmBtu/hr or mmBtu/day).

5.1 Calculate and record heat input to an affected unit on an hourly basis, except as provided below for natural gas, or for units using a common stack, the owner or operator may choose to use the provisions specified in § 75.16(e) in conjunction with the procedures provided below to apportion heat input among each unit using the common stack.

5.2 For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of this part for measuring volumetric flow rate) and a diluent gas (O_2 or CO_2) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input (in mmBtu/hr).

5.2.1 When measurements of CO_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F_c} \frac{\%CO_{2w}}{100}$$

(Eq. F–15)

where,
HI=Hourly heat input, mmBtu/hr.
Q_w=Hourly average volumetric flow rate, wet basis, scfh.
F_c=Carbon-based F-factor, listed in Section 3.3.5 of this appendix for each fuel, scf/mmBtu.
$\%CO_{2w}$=Hourly concentration of CO_2, percent CO_2 wet basis.

5.2.2 When measurements of CO_2 concentrations are on a dry basis, use the following equation:

$$HI = Q_h \left[\frac{(100-\%H_2O)}{100F_c}\right]\left(\frac{\%CO_{2d}}{100}\right)$$

(Eq. F–16)

where
HI=Hourly heat input, mmBtu/hr.
Q_h=Hourly average volumetric flow rate, wet basis, scfh.
F_c=Carbon-based F-Factor, listed above in Section 3.3.5 of this appendix for each fuel, scf/mmBtu.
$\%CO_{2d}$=Hourly concentration of CO_2, $\%CO_2$ dry basis.
$\%H_2O$=Moisture content of gas in the stack, percent.

5.2.3 When measurements of O_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F} \frac{[(20.9/100)(100 - \%H_2O) - \%O_{2w}]}{20.9}$$

(Eq. F–17)

where
HI=Hourly heat input, mmBtu/hr.
Q_w=Hourly average volumetric flow rate, wet basis, scfh.
F=Dry basis F-Factor, listed above in Section 3.3.5 of this appendix for each fuel, dscf/mmBtu.
$\%O_{2w}$=Hourly concentration of O_2, percent O_2 wet basis.
$\%H_2O$=Hourly average stack moisture content, percent by volume.

5.2.4 When measurements of O_2 concentration are on a dry basis, use the following equation:

$$HI = Q_w \left[\frac{(100 - \%H_2O)}{100F}\right]\left[\frac{(20.9 - \%O_{2d})}{20.9}\right]$$

(Eq. F–18)

where,
HI=Hourly heat input, mmBtu/hr.
Q_w=Hourly average volumetric flow, wet basis, scfh.
F=Dry basis F-factor, listed above in Section 3.3.5 of this appendix for each fuel, dscf/mmBtu.
$\%H_2O$=Moisture content of the stack gas, percent.
$\%O_{2d}$=Hourly concentration of O_2, percent O_2 dry basis.

5.3 Whenever a valid hour of flow data has not been obtained and recorded, use the procedures specified in subpart D of this part to provide substitute data.

5.4 Whenever a valid hour of diluent (O_2 or CO_2) concentration data has not been obtained and recorded, substitute for each hour in each missing data period the average of the recorded diluent gas (O_2 or CO_2) percentage concentration for the hour immediately before and the hour immediately following the missing data period.

5.5 For a gas-fired or oil-fired unit that does not have a flow monitor and is using the procedures specified in appendix D to this part to monitor SO_2 emissions or for any affected unit using a common stack for which the owner or operater chooses to determine heat input by fuel sampling and analysis, use the following procedures to calculate hourly (or, when combusting natural gas, daily) heat input in mmBtu/hr or mmBtu/day.

5.5.1 When the unit is combusting oil, use the following equation to calculate hourly heat input.

$$HI_o = M_o \frac{GCV_o}{10^6}$$

(Eq. F–19)

where,
HI_o=Hourly heat input from oil, mmBtu/hr.
M_o=Mass of oil consumed per hour, as determined using procedures in appendix D of this part, in lb, tons, or kg.
GCV_o=Gross calorific value of oil, as measured daily by ASTM D240–87 (Reapproved 1991), ASTM D2015–91, or ASTM D2382–88, Btu/unit mass (incorporated by reference under § 75.6 of this part).
10^6=Conversion of Btu to mmBtu.

5.5.2 When the unit is combusting natural gas, use the following equation to calculate heat input from natural gas for each 24-hour period.

$HI_g = Q_g\ GCV_g$
(Eq. F–20)

where,
HI_g=Daily heat input from natural gas, mmBtu/day.
Q_g=Flow or amount of natural gas combusted during 24-hour period, million cubic feet.
GCV_g=Gross calorific value of natural gas, as verified by the contractual supplier using ASTM D1826–88, Btu/cubic foot (incorporated by reference under § 75.6 of this part).

5.5.3 When the unit is combusting coal, use the procedures, methods, and equations in sections 5.5.3.1–5.5.3.3 of this appendix to determine the heat input from coal for each 24-hour period. (All ASTM methods are incorporated by reference under § 75.6 of this part.)

5.5.3.1 Perform coal sampling daily according to section 5.3.2.2 in Method 19 in Appendix A to part 60 of this chapter and use ASTM Method D2234–89, "Standard Test Methods for Collection of a Gross Sample of Coal," (incorporated by reference under § 75.6 of this part) Type I, Conditions A, B, or C and systematic spacing for sampling.

5.5.3.2 Use ASTM D2013–86, "Standard Method of Preparing Coal Samples for Analysis," for preparation of a daily coal sample and analyze each daily coal sample for gross calorific value using ASTM D2015–91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter." (Both ASTM methods are incorporated by reference under § 75.6 of this part.)

On-line coal analysis may also be used if the on-line analytical instrument has been demonstrated to be equivalent to the applicable ASTM methods.

5.5.3.3 Calculate the heat input from coal using the following equation:

$$HI_c = M_c \frac{GCV_c}{500}$$

(Eq. F–21)

where,

HI_c=Daily heat input from coal, mmBtu/day.

M_c=Mass of coal consumed per day, as measured and recorded in company records, tons.

GCV_c=Gross calorific value of coal sample, as measured by ASTM D3176–89, or D2015–91, Btu/lb.

500=Conversion of Btu/lb to mmBtu/ton.

6. Procedure for Converting Volumetric Flow to STP

Use the following equation to convert volumetric flow at actual temperature and pressure to standard temperature and pressure.

$$F_{STP}=F_{Actual}(T_{Std}/T_{Stack})(P_{Stack}/P_{Std})$$

(Eq. F–22)

where,

F_{STP}=Flue gas volumetric flow rate at standard temperature and pressure, scfh.

F_{Actual}=Flue gas volumetric flow rate at actual temperature and pressure, acfh.

T_{Std}=Standard temperature=68 degrees F.

T_{Stack}=Flue gas temperature at flow monitor location, degrees F.

P_{Stack}=The absolute flue gas pressure=barometric pressure at the flow monitor location + flue gas static pressure, inches of Hg.

P_{Std}=Standard pressure=29.92 inches of Hg.

Appendix G to Part 75—Determination of CO_2 Emissions

1. Applicability

The procedures in this appendix may be used to estimate CO_2 mass emissions discharged to the atmosphere (in tons/day) as the sum of CO_2 emissions from combustion and, if applicable, CO_2 emissions from sorbent used in a wet flue gas desulfurization control system, fluidized bed boiler, or other emission controls.

2. Procedures for Estimating CO_2 Emissions From Combustion

Use the following procedures to estimate daily CO_2 mass emissions from the combustion of fossil fuels. The optional procedure in section 2.3 of this appendix may also be used for an affected gas-fired unit. For an affected unit that combusts any nonfossil fuels (e.g., bark, wood, residue, or refuse), either use a CO_2 continuous emission monitoring system or apply to the Administrator for approval of a unit-specific method for determining CO_2 emissions.

2.1 Use the following equation to calculate daily CO_2 mass emissions (in tons/day) from the combustion of fossil fuels.

$$W_{CO_2}=\frac{(MW_c+MW_{O_2})\times W_c}{2{,}000\ MW_C}$$

(Eq. G–1)

Where,

W_{co2} = CO_2 emitted from combustion, tons/day.

MW_c = Molecular weight of carbon (12.0).

W_{o2} = Molecular weight of oxygen (32.0)

W_c = Carbon burned, lb/day, determined using average weekly fuel analysis by ASTM D3178–89 for coal; or determined by the percentage of carbon in oil from the ultimate analysis of oil, or computed based upon ASTM D3238–90 and either ASTM D2502–87 or ASTM D2503–82 (Reapproved 1987) for oil; or computed based on ASTM D1945–91 or ASTM D1946–90 for gas; and weekly fuel feed rates from company records for all fuels (these six methods are incorporated by reference under § 75.6 of this chapter).

2.2 For an affected coal-fired unit, the estimate of daily CO_2 mass emissions given by Equation G–1 may be adjusted to account for carbon retained in the ash using the procedures in either section 2.21–2.23 or Section 2.24 of the appendix.

2.2.1 Determine the ash content of the weekly sample of coal using ASTM D3174–89 "Standard Test Method for Ash in the Analysis Sample of Coal and Coke From Coal" (incorporated by reference under § 75.6 of this part).

2.2.2 Sample and analyze the carbon content of the fly-ash according to ASTM D3178–89, "Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke" (incorporated by reference under § 75.6 of this part).

2.2.3 Discount the estimate of daily CO_2 mass emissions from the combustion of coal given by Equation G–1 by the percent carbon retained in the ash using the following equation:

$$W_{NCO2}=W_{CO2}-\left(\frac{MW_{CO2}}{MW_c}\right)\left(\frac{A\%}{100}\right)\left(\frac{C\%}{100}\right)W_{COAL}$$

(Eq. G-2)

where,

W_{NCO2} = Net CO_2 mess emissions discharged to the atmosphere, tons/day.

W_{CO2} = Daily CO_2 mass emissions calculated by Equation G–1, tons/day.

MW_{CO2} = Molecular weight of carbon dioxide (44.0).

MW_c = Molecular weight of carbon (12.0).

A% = Ash content of the coal sample, percent by weight.

C% = Carbon content of ash, percent by weight.

W_{COAL} = Feed rate of coal from company records, tons/day.

2.2.4 The daily CO_2 mass emissions from combusting coal may be adjusted to account for carbon retained in the ash using the following equation:

$$W_{NCO2}=.99\ W_{CO2}$$

(Eq. G–3)

where,

W_{NCO2} = Net CO_2 mass emissions from the combustion of coal discharged to the atmosphere, tons/day.

.99 = Average fraction of coal converted into CO_2 upon combustion.

W_{CO2} = Daily CO_2 mass emissions from the combustion of coal calculated by Equation G–1 tons/day.

2.3 In lieu of using the procedures, methods, and equations in Section 2.1 of this appendix, the owner or operator of an affected gas-fired unit may use the following equation and records of daily gas-fired unit may use the following equation and records of daily heat input to estimate daily CO_2 mass emissions (in tons).

$$W_{CO_2}=\left(\frac{F_c\times H\times U_f\times MW_{CO_2}}{2000}\right)$$

(Eq.G–4)

where,

W_{CO2} emitted from combustion, tons/day.

F_c = Carbon-based F-factor, 1,040 scf/mmBtu for natural gas; 1,420 scf/mm/btu for crude, residual, or distillate oil.

H = Daily heat input in mmBtu, as reported in company records.

U_f = 1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F.

3. Procedures for Estimating CO_2 Emissions From Sorbent

When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use either a CO_2 continuous emission monitoring system (consisting of a CO_2 diluent gas monitor and a flow monitor) or use the procedures, methods, and equations in sections 3.1–3.2 of this appendix to determine daily CO_2 mass emissions from the sorbent (in tons).

3.1 When limestone is the sorbent material, use the equations and procedures in either section 3.1.1 or 3.1.2 of this appendix.

3.1.1 Use the following equation to estimate daily CO_2 mass emissions from sorbent (in tons).

$$SE_{CO_2}=W_{CaCO_3}F_s\frac{MW_{CO_2}}{MW_{CaCO_3}}$$

(Eq. G–5)

where,

SE_{CO2}=CO_2 emitted from sorbent, tons/day.

W_{CaCO3}=$CaCO_3$ used, tons/day.

F_s=1.00, the calcium to sulfur stoichiometric ratio.

MW_{CO2}=Molecular weight of carbon dioxide (44).

MW_{CaCO3}=Molecular weight of calcium carbonate (100).

3.1.2 In lieu of using Equation G–5, any owner or operator who operates and maintains a certified SO_2 continuous emission monitoring system (consisting of an SO_2 pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor), for measuring and recording SO_2 emission rate (in lb/mmBtu) at the outlet to the emission controls and who uses the applicable procedures, methods, and equations in § 75.15 of this part to estimate the SO_2 emissions removal efficiency of the emission controls, may use the following equation to estimate daily CO_2 mass emissions from sorbent (in tons).

$$SE_{CO_2} = F_s \frac{W_{SO_2}}{2000} \frac{MW_{CO_2}}{MW_{SO_2}}$$

(Eq. G–6)

where,

$SE=CO_2$ emitted from sorbent, tons/day.

MW_{CO2}=Molecular weight of carbon dioxide (44).

MW_{SO2}=Molecular weight of sulfur dioxide (64).

W_{SO2}=Sulfur dioxide removed, lb/day, based on applicable procedures, methods, and equations in § 75.15 of this part.

F_s=1.0, the calcium to sulfur stoichiometric ratio.

3.2 When a sorbent material other than limestone is used, modify the equations, methods, and procedures in Section 3.1 of this appendix as follows to estimate daily CO_2 mass emissions from sorbent (in tons).

3.2.1 Determine a site-specific value for F_s, defined as the ratio of the number of moles of CO_2 released upon capture of one mole of SO_2, using methods and procedures satisfactory to the Administrator. Use this value of F_s (instead of 1.0) in either Equation G–5 or Equation G–6.

3.2.2 When using Equation G–5, replace MW_{CaCO3}, the molecular weight of calcium carbonate, with the molecular weight of the sorbent material that participates in the reaction to capture SO_2 and that releases CO_2, and replace W_{CaCO3}, the amount of calcium carbonate used (in tons/day), with the amount of sorbent material used (in tons/day).

4. Procedures for Estimating Total CO_2 Emissions

When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use the following equation to obtain total daily CO_2 mass emissions (in tons) as the sum of combustion-related emissions and sorbent-related emissions.

$W_t=W_{CO2}+SE_{CO2}$

(Eq. G–7)

where,

W_t=Estimated total CO_2 mass emissions, tons/day.

$W_{CO2}=CO_2$ emitted from fuel combustion, tons/day.

$SE_{CO2}=CO_2$ emitted from sorbent, tons/day.

Appendix H to Part 75—Revised Traceability Protocol No. 1

This appendix consists of section 3.0.4 of the Quality Assurance Handbook for Air Pollution Measurement Systems, Vol. 3, U.S. Environmental Protection Agency (revised 6/9/87). The Quality Assurance Handbook may be obtained from the Methods Research and Development Division, MD 78–A, Atmospheric Research Exposure and Assessment Laboratory, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

3.0.4. Procedure for NBS-Traceable Certification of Compressed Gas Working Standards Used for Calibration and Audit of Continuous Source Emission Monitors (Revised Traceability Protocol No. 1)

Contents

Subsection	*Title*
3.0.4.0	General Information
3.0.4.1	*Procedure G1:* Assay and Certification of a Compressed Gas Standard Without Dilution
3.0.4.2	References

4.0 General Information

4.0.1 Purpose and Scope of the Procedure

Section 3.0.4 describes a procedure for assaying the concentration of gaseous pollutant concentration standards and certifying that the assay concentrations are traceable to an authoritative reference concentration standard. This procedure is recommended for certifying the local working concentration standards required by the pollutant monitoring regulations of 40 CFR Part 60[1,2] for the calibration and audit of continuous source emission monitors. The procedure covers certification of compressed gas (cylinder) standards for CO, CO_2, NO, NO_2, and SO_2 (Procedure G1).

4.0.2 Reference Standards

Part 60 of the monitoring regulations [1,2] require that working standards used for calibration and audit of continuous source emission monitors be traceable to either a National Bureau of Standards (NBS) gaseous Standard Reference Material (SRM or a NBS/EPA-approved Certified reference material (CRM) [3]. Accordingly, the reference standard used for assaying and certifying a working standard for these purposes must be an SRM, a CRM, or a suitable intermediate standard (see the next paragraph). SRM cylinder gas standards available from NBS are listed in Table 7.2 at the end of subsection 4.0. A current list of CRM cylinder gases and CRM vendors is available from the Quality Assurance Division (MD–77), Environmental Monitoring Systems Laboratory, U.S. EPA, Research Triangle Park, NC 27711.

The EPA regulations define a "traceable" standard as one which"... has been compared and certified, either directly or via not more than one intermediate standard, to a primary standard such as a ... NBS [gaseous] SRM or ... CRM"[4,5]. Certification of a working standard directly to an SRM or CRM primary standard is, of course, preferred and recommended because of the lower error. However, an intermediate reference standard is permitted, if necessary. In particular, a *Gas Manufacturer's Intermediate Standard* (see subsection 4.0.2.1) that has been referenced directly to an SRM or a CRM according to Procedure G1 is an acceptable intermediate standard and could be used as the reference standard on that basis. However, purchasers of commercial gas standards referenced to an intermediate standard such as a GMIS should be aware that, according to the above definition, such a standard would have to be used directly for calibration or audit. Since a second intermediate standard is not permitted, such a standard could not be used as a reference standard to certify other standards.

4.0.2.1 *Gas Manufacturer's Intermediate Standard (GMIS).* A GMIS is a compressed (cylinder) gas standard that has been assayed with direct reference to an SRM or CRM and certified according to Procedure G1, and also meets the following requirements:

1. A candidate GMIS must be assayed a minimum of three (3) times, uniformly spaced over a three (3) month period.

2. Each of the three (or more) assays must be within 1.0 percent of the mean of the three (or more) assays.

3. The difference between the last assay and the first assay must not exceed 1.5 percent of the mean of the three (or more) assays.

4. The GMIS must be recertified every three months, and the reassay must be within 1.5 percent of the previous certified assay. The recertified concentration of the GMIS is the mean of the previous certified concentration and the reassay concentration.

4.0.2.2 *Recertification of Reference Standards.* Recertification requirements for SRMs and CRMs are specified by NBS and NBS/EPA, respectively. See 4.0.2.1 for GMIS recertification requirements.

4.0.3 Using the Procedure

The assay/certification procedure described here is carefully designed to minimize both systematic and random errors in the assay process. Therefore, the procedure should be carried out as closely as possible to the way it is described. Similarly, the assay apparatus has been specifically designed to minimize errors and should be configured as closely as possible to the design specified. Good laboratory practice should be observed in the selection of inert materials (e.g. Teflon, stainless steel, or glass, if possible) and clean, non-contaminating components for use in portions of the apparatus in contact with the candidate or reference gas concentrations.

4.0.4 Certification Documentation

Each assay/certification must be documented in a written certification report signed by the analyst and containing at least the following information:

1. Identification number (cylinder number).

2. Certified concentration of the standard, in ppm or mole percent.

3. Balance gas in the standard mixture.

4. Cylinder pressure at certification.

5. Date of the assay/certification.

6. Certification expiration date (see 4.0.6.3).

7. Identification of the reference standard used: SRM number, cylinder number, and concentration for an SRM; cylinder number and concentration for a CRM or GMIS.

8. Statement that the assay/certification was performed according to this section 3.0.4.

9. Identification of the laboratory where the standard was certified and the analyst who performed the certification.

10. Identification of the gas analyzer used for the certification, including the make, model, serial number, the measurement principle, and the date of the last multipoint calibration.

11. All analyzer readings used during the assay/certification and the calculations used to obtain the reported certified value.

12. Chronological record of all certifications for the standard.

Certification concentrations should be reported to 3 significant digits. Certification documentation should be maintained for at least 3 years.

4.0.5 Certification Label

A label or tag bearing the information described in items 1 through 9 of subsection 4.0.4 must be attached to each certified gas cylinder.

4.0.6 Assay/Certification of Compressed Gas (Cylinder) Standards

4.0.6.1 *Aging of newly-prepared gas standards.* Freshly prepared gas standard concentrations and newly filled gas cylinders must be aged before being assayed and certified. SO_2 concentrations contained in steel cylinders must be aged at least 15 days; other standards must be aged at least 4 days.

4.0.6.2 *Stability test for reactive gas standards.* Reactive gas standards, including nitric oxide (NO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and carbon monoxide (CO), that have not been previously certified must be tested for stability as follows: Reassay the concentration at least 7 days after the first assay and compare the two assays. If the second assay differs from the first assay by 1.5% or less, the cylinder may be considered stable, and the mean of the two assays should be reported as the certified concentration. Otherwise, age the cylinder for a week or more and repeat the test, using the second and third assays as if they were the first and second assays. Cylinders that are not stable may not be sold and/or used for calibration or audit purposes.

4.0.6.3 *Recertification of compressed gas standards.* Compressed gas standards must be recertified according to this section 3.0.4 within the time limits specified in Table 7.1[3,6,7]. The reassay concentration must be within 5% of the previous certified concentration. If not, the cylinder must be retested for stability (subsection 4.0.6.2). The certified concentration of a recertified standard should be reported as the mean of all assays, unless a clear trend or substantial change suggests that previous assays are no longer valid.

TABLE 7.1.—RECERTIFICATION LIMITS FOR COMPRESSED GAS STANDARDS

Pollutant	Balance gas	Concentration range	Maximum months until recertification for cylinder material	
			Al or SS	Other
Carbon monoxide	N_2 or air	≥ 5 ppm	18	6
Nitric oxide	N_2	≥ 10 ppm	18	6
Sulfur dioxide	N_2	≥ 10 ppm	18	6
Nitrogen dioxide	N_2 or air	≥ 10 ppm	6	6
Carbon dioxide	N_2 or air	≥ 300 ppm	18	18
Oxygen	N_2	≥ 2 percent	18	18
Sulfur dioxide and carbon dioxide	N_2	≥ 200 ppm SO_2, 10 percent CO_2	18	6
Propane	N_2 or air	≥ 5 ppm	18	6
Others not specifically listed			6	6

4.0.6.4 *Minimum cylinder pressure.* No compressed gas cylinder standard should be used when its gas pressure is below 700 kPa (100 psi), as indicated by the cylinder pressure gauge.

4.0.6.5 *Assay/certification of multi-component compressed gas standards.* Procedure G1 may be used to assay and certify individual components of multi-component gas standards, provided that none of the components other than the component being assayed cause a detectable response on the analyzer.

4.0.7 Analyzer Calibration

4.0.7.1 *Basic analyzer calibration requirements.* The assay procedure described in this section 3.0.4 employs a direct ratio referencing technique that inherently corrects for minor analyzer calibration variations (drift) and DOES NOT depend on the absolute accuracy of the analyzer calibration. What is required of the analyzer is as follows: 1) it must have a *linear* response to the pollutant of interest (see subsection 4.0.7.5), 2) it must have good resolution and low noise, 3) its response calibration must be reasonably stable during the assay/certification process, and 4) all assay concentration measurements must fall within the calibrated response range of the analyzer.

4.0.7.2 *Analyzer multipoint calibration.* The gas analyzer used for the assay/certification must have had a multipoint calibration within 3 months of its use when used with this procedure. This calibration is *not* used to quantitatively interpret analyzer readings during the assay/certification of the candidate gas because a more accurate, direct ratio comparison of the candidate concentration to the reference standard concentration is used. However, this multipoint calibration is necessary to establish the calibrated range of the analyzer and its response linearity.

The multipoint calibration should consist of analyzer responses to at least 5 concentrations, including zero, approximately evenly spaced over the concentration range. Analyzer response units may be volts, millivolts, percent of scale, or other measurable analyzer response units. The upper range limit of the calibrated range is determined by the highest calibration point used. If the analyzer has a choice of concentration ranges, the optimum range for the procedure should be selected and calibrated. Plot the calibration points and compute the linear regression slope and intercept. See subsection 4.0.7.5 for linearity requirements and the use of a mathematical transformation, if needed. The intercept should be less than 1 percent of the upper concentration range limit, and the correlation coefficient (r) should be at least 0.999.

4.0.7.3 *Zero and span check and adjustment.* On each day that the analyzer will be used for assay/certification, its response calibration must be checked with a zero and at least one span concentration near the upper concentration range limit. If necessary, the zero and span controls of the analyzer should be adjusted so that the analyzer's response (i.e. calibration slope) is within about ±5 percent of the response indicated by the most recent multipoint calibration. If a zero or span adjustment is made, allow the analyzer to stabilize for at least an hour or more before beginning the assay procedure, since some analyzers drift for a period of time following zero or span adjustment. If the analyzer is not in continuous operation, turn it on and allow it to stabilize for at least 12 hours before the zero and span check.

4.0.7.4 *Pollutant standard for multipoint calibration and zero and span adjustment.* The pollutant standard or standards used for multipoint calibration or zero and span checks or adjustments must be obtained from a compressed gas standard certified traceable to an NBS SRM or a NBS/EPA CRM according to Procedure G1 of this section 3.0.4. This standard need not be the same as the reference standard used in the assay/certification. The zero gas must meet the requirements in subsection 4.0.8.

4.0.7.5 *Linearity of analyzer response.* The direct ratio assay technique used in Procedure G1 requires that the analyzer have a linear response to concentration. Linearity is determined by comparing the quantitative difference between a smoothly-drawn calibration curve based on all calibration points and a straight line drawn between zero and an upper reference point (see Figure 1). This difference is measured in concentration units, parallel to the concentration axis, from a point on the calibration curve to the corresponding point for the same response on the straight line.

For the general linearity requirement, the straight line is drawn between zero and the highest calibration point (Figure 1a). Linearity is then acceptable when no point on the smooth calibration curve deviates from the straight line by more than 1.5

percent of the value of the highest calibration concentration. An alternative linearity requirement is defined on the basis of the actual reference and candidate concentrations to be used for the assay. In this case, the reference and candidate concentrations are plotted on the calibration curve, and the straight line is drawn from zero to the reference concentration and extrapolated, if necessary, beyond the candidate concentration (Figure 1b). The deviation of the smooth calibration curve from the straight line at the candidate concentration point then must not exceed 0.8 percent of the value of the reference concentration. This latter specification may allow the use of an analyzer having greater nonlinearity when the reference and candidate concentrations are nearly the same.

For analyzers having an inherently non-linear response, the response can usually be linearized with a simple mathematical transformation of the response values, such as R'=square root(R) or R'=log(R), where R' is the transformed response value and R is the actual analyzer response value. Using the transformed response values, the multipoint calibration should meet one of the above linearity requirements as well as the requirements for intercept and correlation coefficient given in subsection 4.0.7.2.

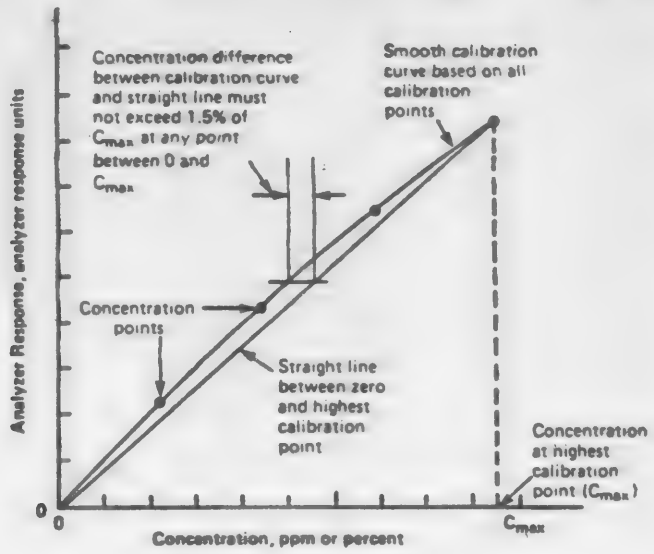
4.0.8 Zero Gas

Zero gas used for dilution of any candidate or reference standard should be clean, dry, zero-grade air or nitrogen containing a concentration of the pollutant of interest equivalent to less than 0.5 percent of the analyzer's upper range limit concentration. The zero gas also should contain no contaminant that causes a detectable response on the analyzer or that suppresses or enhances the analyzer's response to the pollutant. The oxygen content of zero air should be the same as that of ambient air.

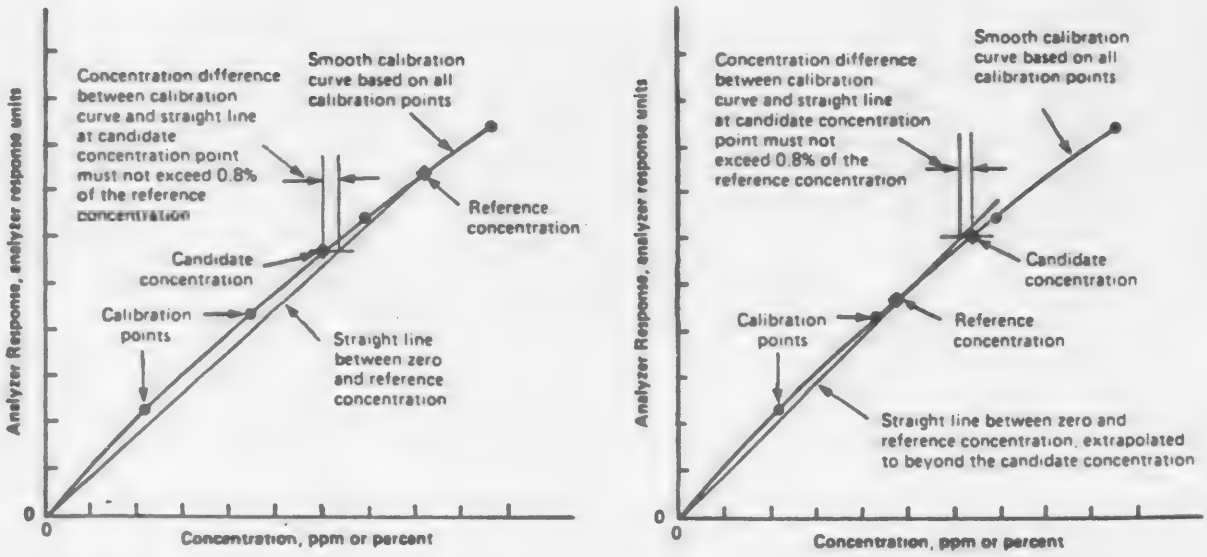
4.0.9 Accuracy Assessment of Commercially Available Standards

Periodically, the USEPA will assess the accuracy of commercially available compressed gas standards that have been assayed and certified according to this section 3.0.4. Accuracy will be assessed by EPA audit analysis of representative actual commercial standards obtained via an anonymous agent. The accuracy audit results, identifying the actual gas manufacturers or vendors, will be published as public information.

BILLING CODE 6560-50-M


Concentration difference between calibration curve and straight line must not exceed 1.5% of C_{max} at any point between 0 and C_{max}
Smooth calibration curve based on all calibration points
Concentration points
Straight line between zero and highest calibration point
Concentration at highest calibration point (C_{max})
Analyzer Response, analyzer response units
0
0
Concentration, ppm or percent
C_{max}

a) General linearity requirement


Concentration difference between calibration curve and straight line at candidate concentration point must not exceed 0.8% of the reference concentration
Smooth calibration curve based on all calibration points
Reference concentration
Candidate concentration
Calibration points
Straight line between zero and reference concentration
Analyzer Response, analyzer response units
0
0
Concentration, ppm or percent
Concentration difference between calibration curve and straight line at candidate concentration point must not exceed 0.8% of the reference concentration
Smooth calibration curve based on all calibration points
Candidate concentration
Calibration points
Reference concentration
Straight line between zero and reference concentration, extrapolated to beyond the candidate concentration
Analyzer Response, analyzer response units
0
0
Concentration, ppm or percent

b) Alternative linearity requirement

Figure 1. Illustration of linearity requirements.

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TABLE 7.2.—NBS SRM REFERENCE GASES

SRM No.	Type	Nominal concentration
2627	NO/N_2	5 ppm.
2628	NO/N_2	10 ppm.
2629	NO/N_2	20 ppm.
1683b	NO/N_2	50 ppm.
1684b	NO/N_2	100 ppm.
1685b	NO/N_2	250 ppm.
1686b	NO/N_2	500 ppm.
1687b	NO/N_2	1000 ppm.
2630	NO/N_2	1500 ppm.
2631	NO/N_2	3000 ppm.
2653	$NO/_2$Air	250 ppm.
2654	$NO/_2$Air	500 ppm.
2655	$NO/_2$Air	1000 ppm.
2656	$NO/_2$Air	2500 ppm.
2612a	CO/Air	10 ppm.
2613a	CO/Air	20 ppm.
2614a	CO/Air	45 ppm.
1677c	CO/N_2	10 ppm.
2635	CO/N_2	25 ppm.
1678c	CO/N_2	50 ppm.
1679c	CO/N_2	100 ppm.
2636	CO/N_2	250 ppm.
1680c	CO/N_2	500 ppm.
1681c	CO/N_2	1000 ppm.
2637	CO/N_2	2500 ppm.
2638	CO/N_2	5000 ppm.
2639	CO/N_2	1 percent.
2640	CO/N_2	2 percent.
2641	CO/N_2	4 percent.
2642	CO/N_2	8 percent.
2657	O_2/N_2	2 percent.
2658	O_2/N_2	10 percent.
2659	O_2/N_2	21 percent.
1693	SO_2/N_2	50 ppm.
1694	SO_2/N_2	100 ppm.
1661a	SO_2/N_2	500 ppm.
1662a	SO_2/N_2	1000 ppm.
1663a	SO_2/N_2	1500 ppm.
1664a	SO_2/N_2	2500 ppm.
1696	SO_2/N_2	3500 ppm.
1670	CO_2/Air	330 ppm.
1671	CO_2/Air	340 ppm.
1672	CO_2/Air	350 ppm.
2632	CO_2/N_2	300 ppm.
2633	CO_2/N_2	400 ppm.
2634	CO_2/N_2	800 ppm.
2619a	CO_2/N_2	0.5 percent.
2720a	CO_2/N_2	1.0 percent.

TABLE 7.2.—NBS SRM REFERENCE GASES—Continued

SRM No.	Type	Nominal concentration
2621a	CO_2/N_2	1.5 percent.
2622a	CO_2/N_2	2.0 percent.
2623a	CO_2/N_2	2.5 percent.
2624a	CO_2/N_2	3.0 percent.
2625a	CO_2/N_2	3.5 percent.
2626a	CO_2/N_2	4.0 percent.
1674b	CO_2/N_2	7.0 percent.
1675b	CO_2/N_2	14.0 percent.
1665b	C_3H_8/Air	3 ppm.
1666b	C_3H_8/Air	10 ppm.
1667b	C_3H_8/Air	50 ppm.
1668b	C_3H_8/Air	100 ppm.
1669b	C_3H_8/Air	500 ppm.
2643	C_3H_8/N_2	100 ppm.
2644	C_3H_8/N_2	250 ppm.
2645	C_3H_8/N_2	500 ppm.
2646	C_3H_8/N_2	1000 ppm.
2647	C_3H_8/N_2	2500 ppm.
2648	C_3H_8/N_2	5000 ppm.
2649	C_3H_8/N_2	1 percent.
2650	C_3H_8/N_2	2 percent.

NBS-SRM cylinders contain approximately 870 liters of gas at STP.

For availability, contact: Office of Standard Reference Materials, Chemistry Building, Room B311, NBS, Gaithersburg, Maryland 20899, (301) 975-6776. (FTS 879-6776).

4.1 *Procedure G1:* Assay and Certification of a Compressed Gas Standard Without Dilution

4.1.1 Applicability

This procedure may be used to assay the concentration of a candidate compressed gas (cylinder) pollutant standard, based on the concentration of a compressed gas (cylinder) reference standard of the same pollutant compound, and certify that the assayed concentration thus established for the candidate standard is traceable to the reference standard. The procedure employs a pollutant gas analyzer to compare the candidate and reference gas concentrations by direct measurement—without dilution of either gas—to minimize assay error.

4.1.2 Limitations

1. The concentration of the candidate gas standard must be between 0.3. and 1.3 times the concentration of the reference gas standard.

2. The analyzer must have a calibrated range capable of directly measuring both the candidate and the reference gas concentrations.

3. The analyzer's response (or transformed response) must be linear with respect to concentration.

4. The balance gas in both the candidate and reference standards must be identical, unless it can be shown that the analyzer is insensitive to any difference in the balance gases.

5. A source of clean, dry zero gas is required.

4.1.3 Assay Apparatus

Figure G1 illustrates the relatively simple assay apparatus. The configuration is designed to allow convenient routing of the zero gas and undiluted samples of the reference gas and candidate gases, in turn, to the analyzer for measurement, as selected by three-way valves V1 and V2. Pressure regulators and needle valves (V3 and V4) control the individual gas flows. The pollutant concentrations are delivered to the analyzer via a vented tee, which discharges excess flow and insures that the assay concentrations sampled by the analyzer are always at a fixed (atmospheric) pressure. A small, uncalibrated rotameter monitors the vent flow to verify that the total gas flow rate exceeds the sample flow rate demand of the analyzer so that no room air is admitted through the vent. Valves V1 and V2 could be replaced by a single four-way valve (with 3 inputs and 1 output) or by manually moving the output connection to each of the gases as needed. See also subsection 4.0.3.

BILLING CODE 6560-50-M

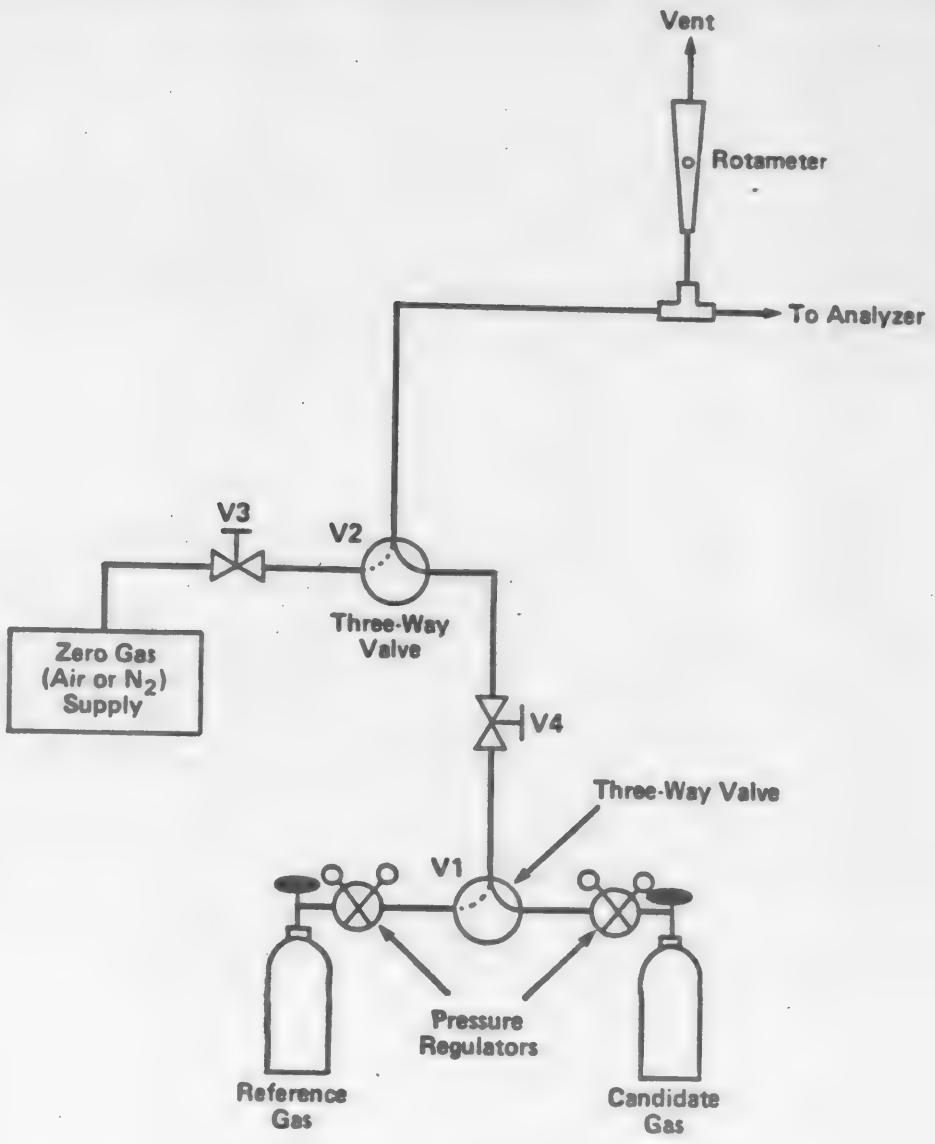

Figure G1. Suggested assay apparatus for Procedure G1.

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4.1.4 Analyzer

See subsection 4.0.7.1. The pollutant gas analyzer must have a linear response function and a calibrated range capable of measuring the full concentration of both the candidate and the reference gas standards directly, without dilution. It must have good resolution (readability), good precision, a stable response, and low output signal noise. In addition, the analyzer must have good specificity for the pollutant of interest so that it has no detectable response to any contaminant that may be contained in either the candidate or reference gas. If the candidate and reference gases contain dissimilar balance gases (air versus nitrogen or different proportions of oxygen in the balance air, for example), the analyzer must be proven to be insensitive to the different balance gases. This may be accomplished by showing no difference in analyzer response when measuring pollutant concentrations diluted with identical flow rates of the two balance gases.

The analyzer should be connected to a suitable, precision chart recorder or other data acquisition device to facilitate graphical observation and documentation of the analyzer responses obtained during the assay.

4.1.5 Analyzer Calibration

4.1.5.1 *Multipoint calibration.* See subsections 4.0.7.2 and 4.0.7.4.

4.1.5.2 *Calibration range.* The calibrated range of the analyzer must include both the candidate and reference gas concentrations, such that the higher concentration does not exceed 97 percent of the upper range limit, and the lower concentration is not below 25 percent of the upper range limit (assuming a lower range limit of zero). Within these limits, select a calibrated analyzer range that will produce the highest analyzer responses.

4.1.5.3 *Linearity.* The direct ratio assay technique used in this procedure requires that the analyzer have a linear response to concentration (see subsection 4.0.7.5). High-concentration-range analyzers of the type that are required for this procedure may not be inherently linear, but they usually have a predictable, non-linear response characteristic that can be mathematically transformed to produce a sufficiently linear response characteristic suitable for use in this procedure. Any such response transformation should be verified by using it for the multipoint calibration. Caution should be exercised in using a transformed response curve because physical zero or span adjustments to the analyzer may produce unexpected effects on the transformed characteristic.

4.1.5.4 *Zero and span adjustment.* See subsections 4.0.7.3 and 4.0.7.4. Prior to carrying out the assay/certification procedure, check the calibration of the analyzer and, if necessary, adjust the analyzer's zero and span controls to reestablish the response characteristic determined at the most recent multipoint calibration. Allow the analyzer to stabilize for an hour or more after any zero or span adjustment. If there is any doubt that a transformed response characteristic is still linear following a zero or span adjustment, verify linearity with a multipoint calibration (subsection 4.0.7.2) using at least 3 known pollutant concentrations, including zero.

4.1.6 Assay Gases

4.1.6.1 *Candidate gas standard.* See subsections 4.0.6 and 4.1.2.

4.1.6.2 *Reference gas standard.* See subsections 4.0.2, 4.1.2, and 4.0.6.4. Select a reference standard such that the concentration of the candidate gas is not more than 30 percent above nor less than 70 percent below the concentration of the standard.

4.1.6.3 *Zero gas.* See subsection 4.0.8. The zero gas should match the balance gas used in the cylinder concentrations.

4.1.7 Assay Procedure

1. Verify that the assay apparatus is properly configured, as described in subsection 4.1.3 and shown in Figure G1.

2. Verify that the linearity of the analyzer has been checked within the last 3 months (see subsections 4.0.7.2, 4.0.7.5, and 4.1.4), that the zero and span are adjusted correctly (subsection 4.0.7.3), that the candidate and reference gas concentrations are within 25 and 97 percent of the upper range limit of the calibrated measurement range of the analyzer, and that the analyzer is operating stably.

3. Adjust the flow rates of the three gases (reference, candidate, and zero) to approximately the same value that will provide enough flow for the analyzer and sufficient excess to assure that no ambient air will be drawn into the vent.

4. Conduct a triad of measurements with the analyzer. Each triad consists of a measurement of the zero gas concentration, a measurement of the reference gas concentration, and a measurement of the candidate gas concentration. Use valves V1 and V2 to select each of the three concentrations for measurement. For each measurement, allow ample time for the analyzer to achieve a stable response reading. Record the stable analyzer response for each measurement, using the same response units (volt, millivolts, percent of scale, etc.) used for the multipoint calibration and any transformation of the response readings necessary for linearity. Do not translate the response readings to concentration values via the calibration curve (see the footnote following Equation G1). Do not make any zero, span, or other physical adjustments to the analyzer during the triad of measurements.

5. Conduct at least 2 additional measurement triads, similar to step 4 above. However, for these subsequent triads, change the order of the three measurements (e.g. measure reference gas, zero gas, candidate gas for the second triad and zero gas, candidate gas, reference gas for the third triad, etc.).

6. If any one or more of the measurements of a triad is invalid or abnormal for any reason, discard all three measurements of the triad and repeat the triad.

7. For each triad of measurements, calculate the assay concentration of the candidate gas as follows:

$$C_C = C_r \frac{R_C - R_Z}{R_r - R_Z}$$

Equation G1

where:

C_c=Assay concentration of the candidate gas standard, ppm or percent;

C_r=Concentration of the reference gas standard, ppm or percent;

R_c=Stable response reading of the analyzer for the candidate gas, analyzer response units;*

R_z=Stable response reading of the analyzer for the zero gas, analyzer response units;*

R_r=Stable response reading of the analyzer for the reference gas, analyzer response units.*

*Analyzer response units are the units used to express the *direct* response readings of the analyzer, such as volts, millivolts, percent of scale, etc. DO NOT convert these direct response readings to concentration units with the multipoint calibration curve or otherwise adjust these readings except for transformation necessary to achieve response linearity.

8. Calculate the mean of the 3 (or more) valid assays. Calculate the percent difference of each assay from the mean. If any one of the assay values differs from the mean by more than 1.5%, discard that assay value and conduct another triad of measurements to obtain another assay value. When at least 3 assay values all agree within 1.5% of their mean, report the mean value as the certified concentration of the candidate gas standard. For newly-prepared reactive standards, a reassay at least 7 days later is required to check the stability of the standard; see subsection 4.0.6.2.

4.1.8 Stability Test for Newly-Prepared Standards

See subsections 4.0.6.1 and 4.0.6.2.

4.1.9 Certification Documentation

See subsections 4.0.4 and 4.0.5.

4.1.10 Recertification Requirements

See subsections 4.0.6.3 and 4.0.6.4.

4.2 References

1. *Code of Federal Regulations*, Title 40, part 60, "Standards of Performance for New Stationary Sources," Appendix A, Method 20 (1982).

2. Standards of Performance for New Stationary Sources; Quality Assurance Requirements for Gaseous Continuous Emission Monitoring Systems Used for Compliance Determination, promulgated in the **Federal Register**, June 4, 1987, pp. 21003–21010.

3. "A Procedure for Establishing Traceability of Gas Mixtures to Certain National Bureau of Standards Standard Reference Materials. EPA–600/7–81–010. Joint publication by NBS and EPA, May 1981. Available from the U.S. Environmental Protection Agency, Environmental Monitoring Systems Laboratory (MD–77), Research Triangle Park, NC 27711.

4. *Code of Federal Regulation*, Title 40, part 50, "National Ambient Air Quality Measurement Methodology".

5. *Code of Federal Regulations*, Title 40, part 58, "Ambient Air Quality Surveillance," Appendixes A and B.

6. Shores, R.C. and F. Smith, "Stability Evaluation of Sulfur Dioxide, Nitric Oxide, and Carbon Monoxide Gases in Cylinders. NTIS No. PB 85–122646. Available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA 22161.

7. Method 6A and 6B, "Determination of Sulfur Dioxide, Moisture, and Carbon Dioxide Emissions from Fossil Fuel Combustion Sources," *Quality Assurance Handbook for Air Pollution Measurement Systems*, Volume III, Section 3.13.8, July 1986. Available from the U.S. Environmental Protection Agency, Center for Environmental Research Information, Cincinnati, OH 45268.

8. "List of Designated Reference and Equivalent Methods." Current edition available from the U.S. Environmental Protection Agency, Environmental Monitoring Systems Laboratory, Quality Assurance Division (MD–77), Research Triangle Park, NC 27711.

Appendix I of Part 75

[This appendix is reserved.]

7. Title 40 is amended by adding part 77 to read as follows:

PART 77—EXCESS EMISSIONS

Sec.

77.1 Purpose and scope.
77.2 General.
77.3 Offset plans for excess emissions of sulfur dioxide.
77.4 Administrator's action on proposed offset plans.
77.5 Deduction of allowances to offset excess emissions of sulfur dioxide.
77.6 Penalties for excess emissions of sulfur dioxide and nitrogen oxides.

Authority: 42 U.S.C. 7651j.

PART 77—EXCESS EMISSIONS

§77.1 Purpose and scope.

(a) This part sets forth the excess emissions offset planning and offset penalty requirements under section 411 of the Clean Air Act, 42 U.S.C. 7401, et seq., as amended by Public Law 101–549 (November 15, 1990). These requirements shall apply to the owners and operators and, to the extent applicable, the designated representative of each affected unit and affected source under the Acid Rain Program.

(b) Nothing in this part shall limit or otherwise affect the application of sections 112(r)(9), 113, 114, 120, 303, 304, or 306 of the Act, as amended. Any allowance deduction, excess emission penalty, or interest required under this part shall not affect the liability of the affected unit's and affected source's owners and operators for any additional fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the Act.

§77.2 General.

Part 72 of this chapter, including §§ 72.2 (definitions), 72.3 (measurements, abbreviations, and acronyms), 72.4 (federal authority), 72.5 (State authority), 72.6 (applicability), 72.7 (new units exemption), 72.8 (retired units exemption), 72.9 (standard requirements), 72.10 (availability of information), and 72.11 (computation of time), shall apply to this part. The procedures for appeals of decisions of the Administrator under this part are contained in part 78 of this chapter.

§77.3 Offset plans for excess emissions of sulfur dioxide.

(a) *Applicability.* The owners and operators of any affected unit that has excess emissions of sulfur dioxide in any calendar year shall be liable to offset the amount of such excess emissions by an equal amount of allowances from the unit's Allowance Tracking System account.

(b) *Deadline.* Not later than 60 days after the end of any calendar year during which an affected unit had excess emissions of sulfur dioxide (except for any increase in excess emissions under § 72.91(b) of this chapter), the designated representative for the unit shall submit to the Administrator a complete proposed offset plan to offset those emissions. Each day after the 60-day deadline that the designated representative fails to submit a complete proposed offset plan shall be a separate violation of this part.

(c) *Number of Plans.* The designated representative shall submit a proposed offset plan for each affected unit with excess emissions of sulfur dioxide.

(d) *Contents of Plan.* A complete proposed offset plan shall include the following elements in a format prescribed by the Administrator for the unit and for the calendar year for which the plan is submitted:

(1) Identification of the unit.

(2) If the unit had excess emissions for the calendar year prior to the year for which the plan is submitted, an explanation of how and why the excess emissions occurred for the year for which the plan is submitted and a description of any measures that were or will be taken to prevent excess emissions in the future.

(3) The amount of excess emissions of sulfur dioxide (in tons/year) for the year for which the plan is submitted and the number of allowances required to be deducted from the unit's Allowance Tracking System account to offset the excess emissions.

(4) At the designated representative's option, the serial numbers of the allowances that are to be deducted from the unit's Allowance Tracking System account.

(5) Whether the allowances are to be deducted immediately from the unit's account or, if not, the date on which they are to be deducted.

(6) If the proposed offset plan does not propose a deduction of the amount of allowances under paragraph (d)(3) of this section from the compliance subaccount during the year after the year for which the plan is submitted, a demonstration that such a deduction will interfere with electric reliability.

§77.4 Administrator's action on proposed offset plans.

(a) *Determination of Completeness.* The Administrator will determine whether the proposed offset plan is complete within 30 days of receipt by the Administrator. The offset plan shall be deemed complete if the Administrator fails to notify the designated representative to the contrary within 30 days of receipt or when the Administrator approves the offset plan and deducts allowances in accordance with paragraph (b)(1) of this section.

(b) *Review of proposed offset plans.* (1) If the designated representative submits a complete proposed offset plan for immediate deduction, from the unit's compliance subaccount, of all allowances required to offset excess emissions of sulfur dioxide, the Administrator will approve the proposed offset plan without further review and will serve written notice of any approval on the designated representative and on any persons entitled to written notice under paragraphs (g)(2)(i) (B), (C) and (D) of this section. The Administrator will also give notice of any approval in the **Federal Register**. The plan will be incorporated into the unit's Acid Rain permit in accordance with § 72.84 (automatic permit amendment) and will not be subject to the requirements of paragraphs (d) through (k) of this section.

(2) Notwithstanding paragraph (b)(1) of this section, the Administrator may, in his or her discretion, require that the proposed offset plan under paragraph (b)(1) of this section be reviewed under paragraphs (c) through (k) of this section. The Administrator may exercise such discretion where he or she determines that review of the plan is necessary to ensure compliance with the

emissions limitation and reduction goals or other purposes of title IV of the Act.

(3) If the designated representative submits a complete proposed offset plan that does not meet the requirements of paragraph (b)(1) of this section, the Administrator will review the plan under paragraphs (c) through (k) of this section.

(c) *Supplemental Information.* (1)(i) Regardless of whether the proposed offset plan is complete under paragraph (a) of this section, the Administrator may require submission of any additional information that the Administrator determines is necessary to approve an offset plan.

(ii) Such supplemental information may include, but is not limited to:

(A) A description of the measures that are proposed to be taken to ensure that the unit will have sufficient allowances to offset the excess emissions and to prevent excess emissions in future years;

(B) A schedule of compliance with appropriate increments of progress for the proposed measures; and

(C) A schedule for the submission of progress reports, and supporting documentation, describing actions taken and actions remaining to be taken under the schedule of compliance and any proposed adjustments to the schedule of compliance.

(2)(i) The designated representative shall submit the information required under paragraph (c)(1) of this section within 30 days after he or she is notified of the requirement for supplemental information unless the Administrator allows for additional time to collect and submit the information.

(ii) If the designated representative fails to submit the supplemental information within the required time period, the Administrator may disapprove the proposed offset plan.

(d) *Draft Offset Plan.* (1) After the Administrator receives a complete proposed offset plan and any supplemental information, the Administrator will prepare a draft offset plan that incorporates in whole, in part, or with changes or conditions as appropriate, the proposed offset plan or disapprove a draft offset plan for the affected unit. Regardless of whether the Administrator required the submission of the information set forth in paragraph (c)(1)(ii) of this section, the draft offset plan may include, among other requirements and conditions as determined to be appropriate by the Administrator, the submission of schedules of compliance, progress reports, and monitoring and other information.

(2) The draft offset plan will be based on the information submitted by the designated representative for the affected unit and other relevant information.

(3) The Administrator will serve a copy of the draft offset plan and the statement of basis on the designated representative of the affected unit.

(4) The Administrator will provide a 30-day period for public comment, and opportunity to request a public hearing, on the draft offset plan or disapproval of a draft offset plan in accordance with the public notice required under paragraph (g)(1)(i)(A) of this section.

(e) *Offset Plan Administrative Record.* (1) The Administrator will prepare an administrative record for an offset plan or disapproval of an offset plan. The administrative record will contain:

(i) The proposed offset plan and any supporting or supplemental information submitted by the designated representative;

(ii) The draft offset plan;

(iii) The statement of basis;

(iv) Copies of all documents relied on by the Administrator in approving or disapproving the draft offset plan (including any records of discussions or conferences with owners, operators or the designated representative of the unit or interested persons regarding the draft offset plan) or, for any such documents that are readily available, a statement of their location;

(v) Copies of all written public comments submitted on the draft offset plan or disapproval of a draft offset plan;

(vi) The record of any public hearing on the draft offset plan or disapproval of a draft offset plan;

(vii) The offset plan approved by the Administrator; and

(viii) Any response to public comments submitted on the draft offset plan or disapproval of a draft offset plan, including any documents cited in the response and any other documents relied on by the Administrator or, for any such documents that are readily available, a statement of their location.

(2) The Administrator will approve or disapprove an offset plan within 6 months of receipt of a complete proposed offset plan.

(f) *Statement of Basis.* (1) The statement of basis will briefly set forth significant factual, legal, and policy considerations on which the Administrator relied in approving or disapproving the draft offset plan.

(2) The statement of basis will include:

(i) The reasons, and supporting authority, for approval or disapproval of any proposed offset plan that does not require deduction of allowances during the year after the year for which the plan is submitted, including references to applicable statutory or regulatory provisions and to the administrative record; and

(ii) The name, address, and telephone and facsimile number of the EPA office processing the approval or disapproval of the offset plan.

(g) *Opportunities for Public Comment on Draft Offset Plans.*

(1) *Generally.* (i) The Administrator will give public notice of the following:

(A) The draft offset plan or disapproval of a draft offset plan and the opportunity for public comment and to request a public hearing; and

(B) Date, time, location, and procedures for any scheduled hearing on the draft offset plan or the disapproval of a draft offset plan.

(ii) Any public notice given under this section may be for the approval or disapproval of one or more draft offset plans.

(2) *Methods.* The Administrator will give the public notice required by this section by:

(i) Serving written notice on the following persons (except to the extent any such person has waived his or her right to receive such notice):

(A) The designated representative;

(B) The State or local air pollution agency and any utility regulatory authority with jurisdiction over the owners of the unit covered by the proposed offset plan;

(C) The State or local air pollution agency for any contiguous State whose air quality may be affected by, or for any State located within a 50-mile radius of, the unit covered by the proposed offset plan; and

(D) Any interested person.

(ii) Giving notice by publication in the Federal Register and in a newspaper of general circulation in the area where the unit is located or in a State publication designed to give general public notice.

(3) *Contents.* All public notices issued under this part will contain the following information:

(i) Identification of the EPA office processing the approval or disapproval of the draft offset plan for which the notice is being given.

(ii) Identification of the designated representative for the affected unit.

(iii) Identification of each affected unit covered by the proposed offset plan.

(iv) The amount of excess emissions that must be offset and the date on which the allowances are proposed to be deducted.

(v) The address and office hours of a public location where the

administrative record is available for public inspection and a statement that all information submitted by the designated representative and not protected as confidential pursuant to section 114(c) of the Act is available for public inspections as part of the administrative record.

(vi) For public notice under paragraph (g)(1)(i)(A) of this section, a brief description of the public comment procedures, including:

(A) A 30-day public comment period beginning the date of publication of the notice or, in the case of an extension or reopening of the public comment period, such period as the Administrator deems appropriate;

(B) The address where public comments should be sent;

(C) Required formats and contents for public comment;

(D) An opportunity to request a public hearing to occur not earlier than 15 days after public notice is given and the location, date, time, and procedures of any scheduled public hearing; and

(E) Any other means by which the public may participate.

(4) *Extensions and Reopenings of the Public Comment Period.* On the Administrator's own motion, or on the request for any person, the Administrator may, at his or her discretion, extend or reopen the public comment period where he or she finds that doing so will contribute to the decision-making process by clarifying one or more significant issues affecting the draft offset plan or disapproval of a draft offset plan. Notice of any such extension or reopening will be given under paragraph (g)(1)(i)(A) of this section.

(h) *Public comments.* (1) General. During the public comment period, any person may submit written comments on the draft offset plan or disapproval of a draft offset plan.

(2) Form. (i) Comments shall be submitted in duplicate.

(ii) The submission shall clearly indicate the draft offset plan approval or disapproval to which the comments apply.

(iii) The submission shall clearly indicate the name of the commenter, his or her interest, and his or her affiliation, if any, to owners and operators of any unit covered by the proposed offset plan.

(3) Contents. Timely comments on any aspect of a draft offset plan or disapproval of a draft offset plan will be considered unless they concern issues that are not relevant, such as:

(i) The environmental effects of acid rain, acid deposition, sulfur dioxide, or nitrogen oxides generally; and

(ii) Offset plan approval procedures or actions on other proposed offset plans that are not relevant to approval or disapproval of the draft offset plan in question.

(4) Persons who do not wish to raise issues on the draft offset plan or denial of a draft offset plan, but who wish to be notified of any subsequent actions concerning such matter, may so indicate during the public comment period or at any other time. The Administrator will place their names on a list of interested persons.

(i) *Opportunity for Public Hearing.* (1) During the public comment period, any person may request a public hearing. A request for a public hearing shall be made in writing and shall state the issues proposed to be raised in the hearing.

(2) On the Administrator's own motion or on the request of any person, the Administrator may, at his or her discretion, hold a public hearing whenever the Administrator finds that such a hearing will contribute to the decision-making process by clarifying one or more significant issues affecting the draft offset plan or disapproval of a draft offset plan. Public hearings will not be held on issues under paragraphs (h)(3) (i) and (ii) of this section.

(3) During a public hearing under this section, any person may submit oral or written comments concerning the draft offset plan or disapproval of a draft offset plan. The Administrator may set reasonable limits on the time allowed for oral statements and will require the submission of written summaries of each oral statement.

(4) The Administrator will assure that a record is made of the hearing.

(j) *Response to Comments.* (1) The Administrator will consider comments on the draft offset plan or disapproval of a draft offset plan received during the public comment period and any public hearing. The Administrator is not required to consider comments otherwise received.

(2) In approving or disapproving an offset plan, the Administrator will:

(i) Identify any draft offset plan provision or portion of the statement of basis that has been changed and the reasons for the change; and

(ii) Briefly describe and respond to relevant comments under paragraph (j)(1) of this section.

(k) *Approval and Effective Date of Excess Emissions Offset Plans.* (1) After the close of the public comment period, the Administrator will approve an offset plan requiring allowance deductions in an amount equal to the unit's tons of excess emissions or disapprove an offset plan. The Administrator will serve a copy of any approved offset plan and the response to comment on the designated representative for the affected unit involved and serve written notice of the approval or disapproval of the offset plan on any persons who are entitled to written notice under paragraphs (g)(2)(i) (B), (C), and (D) of this section. The Administrator will also give notice in the **Federal Register**.

(2) The Administrator will approve an offset plan requiring deduction from the unit's compliance subaccount, by December 31 of the year after the year for which the report is submitted, of all allowances necessary to offset the excess emissions except to the extent the designated representative of the unit demonstrates that such a deduction will interfere with electric reliability.

(3) Upon approval of the offset plan by the Administrator, the offset plan will be incorporated into the Acid Rain permit in accordance with § 72.84 (automatic permit amendment) and shall supersede any inconsistent provision of the permit.

§ 77.5 Deduction of allowances to offset excess emissions of sulfur dioxide.

(a) The Administrator will deduct allowances to offset excess emissions in accordance with the offset plan approved under § 77.4(b) (1) or (k) or in accordance with § 72.91(b) of this chapter.

(b) The designated representative shall hold enough allowances in the appropriate compliance subaccount to cover the deductions to be made in accordance with paragraph (a) or paragraph (c) of this section.

(c) If the designated representative does not submit a timely and complete proposed offset plan, or if the Administrator disapproves a proposed offset plan under § 77.4 (c) or (k), the Administrator will immediately deduct allowances, from the unit's compliance subaccount on a first-in, first-out basis in accordance with § 73.35(c)(2) of this chapter, equal to the amount of the unit's excess emissions of sulfur dioxide.

(d) If a compliance subaccount does not contain adequate allowances to offset the excess emissions, the Administrator will deduct the required allowances whenever allowances are recorded to that account.

§ 77.6 Penalties for excess emissions of sulfur dioxide and nitrogen oxides.

(a) If excess emissions of sulfur dioxide or nitrogen oxides occur at an affected unit during any year, the owners and operators of the affected unit shall pay, without demand, an excess emissions penalty, as calculated

under paragraph (b) of this section. Such payment shall be submitted to the Administrator no later than 60 days after the end of any year during which excess emissions occurred at an affected unit or, for any increase in excess emissions of sulfur dioxide determined after adjustments made under § 72.91(b) of this chapter, by July 31 of the year in which the adjustments are made. Each day after the applicable deadline that the payment is not submitted shall be a separate violation of this part.

(b) *Penalty Formula.* (1) The following formulas shall be used to determine the excess emissions penalty:

Penalty for excess emissions of sulfur dioxide=$2000/ton × annual adjustment factor × tons of excess emissions of sulfur dioxide.

Penalty for excess emissions of nitrogen oxides=$2000/ton × annual adjustment factor × tons of excess emissions of nitrogen oxides.

(i) The annual adjustment factor will be calculated as follows:

Annual adjustment factor=1+{[CPI(year)–CPI(1990)]/CPI(1990)}

where:

(A) "CPI(year)" is the Consumer Price Index as defined in § 72.2 of this chapter and "year" is the year in which the unit had excess emissions.

(B) "CPI(1990)" is the Consumer Price Index for 1990, as defined in § 72.2 of this chapter.

(ii) The Administrator will publish the annual adjustment factor in the **Federal Register** by October 15 of each year beginning in 1995.

(2) The penalty may be rounded to the nearest dollar after completing the calculation in paragraph (b)(1)(i) of this section.

(3) The penalty for excess emissions of sulfur dioxide shall be paid separately from the payment for excess emissions of nitrogen oxides. Each payment shall be accompanied by a document, in a format prescribed by the Administrator, indicating the unit for which the payment is made, whether the payment is for excess emissions of sulfur dioxide or nitrogen oxides, the number of tons of excess emissions, the penalty amount, and the check or money order number of the payment.

(c) If an excess emissions penalty due under this part is not paid on or before the applicable deadline under paragraph (a) of this section, the penalty shall be subject to interest charges in accordance with the Debt Collection Act (31 U.S.C. 3717). Interest shall begin to accrue on the date on which the Administrator mails, to the designated representative of the unit with excess emissions, a demand notice for the payment.

(d)(1) Except for wire transfers made in accordance with paragraph (d)(2) of this section, payments of penalties shall be made by money order, cashier's check, certified check, or U.S. Treasury check made payable to the "U.S. EPA."

(2) Payments made under paragraph (c)(1) of this section shall be mailed to the following address, unless the Administrator has notified the designated representative of a different address: U.S. EPA: Headquarters Accounting Operations Branch, Acid Rain Excess Emissions Penalties, P.O. Box 952491, St. Louis, MO 63195–2491.

(3) Payments of penalties of $25,000 or more may be made by wire transfer to the U.S. Treasury at the Federal Reserve Bank of New York.

(e) If the Administrator determines that overpayment has been made, he or she will refund the overpayment without interest, as promptly as administratively possible.

(f) Excess emissions in any year resulting directly from an order issued in that year under section 110(f) of the Act shall not be subject to the penalty payment requirements of this section; *provided* that the designated representative of any unit subject to such order shall advise the Administrator within 30 days of issuance of the order that the order will result in such excess emissions.

8. Title 40 is amended by adding part 78 to read as follows:

PART 78—APPEAL PROCEDURES FOR ACID RAIN PROGRAM

Sec.

78.1 Purpose and scope.
78.2 General.
78.3 Petition for administrative review and request for evidentiary hearing.
78.4 Filings.
78.5 Limitation on filing or presenting new evidence and raising new issues.
78.6 Action on petition for administrative review.
78.7 Stays of contested Acid Rain requirements pending appeal.
78.8 Consolidation and severance of appeals proceedings.
78.9 Notice of the filing of petition for administrative review.
78.10 *Ex parte* communications during pendency of a hearing.
78.11 Intervenors.
78.12 Standard of review.
78.13 Scheduling orders and pre-hearing conferences.
78.14 Evidentiary hearing procedure.
78.15 Motions in evidentiary hearings.
78.16 Record of appeal proceeding.
78.17 Proposed findings and conclusions and supporting brief.
78.18 Proposed decision.
78.19 Interlocutory appeal.
78.20 Appeal of decision of Administrator or proposed decision to the Environmental Appeals Board.

Authority: 42 U.S.C. 7601 and 7651, et. seq.

PART 78—APPEAL PROCEDURES FOR ACID RAIN PROGRAM

§ 78.1 Purpose and scope.

(a) This part shall govern appeals of any decision of the Administrator under the Acid Rain Program that, in the absence of an administrative appeal, will be final agency action; *provided* that matters listed in § 78.3(d) and interim decisions, such as draft Acid Rain permits or proposed alternative monitoring systems, may not be appealed.

(b) The decisions of the Administrator that may be appealed include but are not limited to:

(1) Under part 72 of this chapter;

(i) The determination of incompleteness of an Acid Rain permit application;

(ii) The issuance or denial of an Acid Rain permit and approval or disapproval of a compliance option by the Administrator;

(iii) The approval or disapproval of an early ranking application for Phase I extension under § 72.42 of this chapter;

(iv) The final determination of whether a technology is a qualified repowering technology under § 72.44 of this chapter;

(v) The issuance or denial of a written exemption for new units or retired units under §§ 72.7 and 72.8 of this chapter;

(vi) The approval or disapproval of a permit revision;

(vii) The decision on the deduction or return of allowances under §§ 72.41, 72.42, 72.43, 72.44, 72.91(b), and 72.92 (a) and (c) of this chapter; and

(viii) The failure to issue an Acid Rain permit in accordance with the deadline under § 72.74(b) of this chapter.

(2) Under part 73 of this chapter,

(i) The decision on a claim of error in a transfer recordation;

(ii) The decision on the allocation of allowances from the Conservation and Renewal Energy Reserve;

(iii) The decision on the allocation of allowances under regulations implementing sections 404(e), 405(g)(4), 405(i)(2), and 410(h) of the Act;

(iv) The decision on the allocation of allowances under part 73, subpart F of this chapter;

(v) The decision on the sale or return of allowances and transfer of proceeds under part 73, subpart E; and

(vi) The decision on the deduction of allowances under § 73.35(b) of this chapter.

(3) Under part 75 of this chapter,

(i) The decision on a petition for approval of an alternative monitoring system;

(ii) The approval or disapproval of a monitoring system certification or recertification;

(iii) The finalization of annual emissions data, including retroactive adjustment based on audit;

(iv) The determination of the percentage of emissions reduction achieved by qualifying Phase I technology; and

(v) The determination on the acceptability of parametric missing data procedures for a unit equipped with add-on controls for sulfur dioxide and nitrogen oxides in accordance with part 75 of this chapter.

(4) Under part 77 of this chapter, the determination of incompleteness of an offset plan and the approval or disapproval of an offset plan under § 77.4 of this chapter and the deduction of allowances under § 77.5(c) of this chapter.

(c) In order to appeal a decision under paragraph (a) of this section, a person shall file a petition for administrative review with the Environmental Appeals Board under § 78.3. The Environmental Appeals Board will, consistent with § 78.6, either:

(1) Issue an order deciding the appeal; or

(2) Where there is a disputed issue of fact material to the contested portions of the decision, refer the proceeding to the Chief Administrative Law Judge, who will designate an Administrative Law Judge to conduct an evidentiary hearing to decide the disputed issue of fact. If the proposed decision is contested or the Environmental Appeals Board decides to review the proposed decision, the Environmental Appeals Board will issue an order deciding the appeal.

(d) Questions arising at any stage of a proceeding that are not addressed in this part will be resolved at the discretion of the Environmental Appeals Board or the Presiding Officer.

§ 78.2 General.

Part 72 of this chapter, including sections 72.2 (definitions), 72.3 (measurements, abbreviations, and acronyms), 72.4 (federal authority), 72.5 (State authority), 72.6 (applicability), 72.7 (new units exemption), 72.8 (retired units exemption), 72.9 (standard requirements), 72.10 (availability of information), and 72.11 (computation of time), shall apply to this part.

§ 78.3 Petition for administrative review and request for evidentiary hearing.

(a)(1) The following persons may petition for administrative review of a decision of the Administrator that is made under parts 72, 75, and 77 of this chapter and that is appealable under § 78.1(a) of this part:

(i) The designated representative for the unit covered by the decision;

(ii) The authorized account representative for an account covered by the decision; and

(iii) Any interested person.

(2) The following persons may petition for administrative review of a decision of the Administrator that is made under part 73 of this chapter and that is appealable under § 78.1(a):

(i) The authorized account representative for any Allowance Tracking System account covered by the decision; and

(ii) With regard to the decision on the allocation of allowances from the Conservation and Renewable Energy Reserve, the certifying official whose application is covered by the decision.

(b)(1) Within 60 days following issuance of a decision under § 78.1 of this part by the Administrator, any person under paragraph (a) of this section may file a petition with the Environmental Appeals Board for administrative review of the decision. If no petition for administrative review of a decision under § 78.1 of this part is filed within such period, the decision shall become final agency action.

(2) The petition may include a request for an evidentiary hearing to resolve any disputed issue of material fact concerning the decision.

(3) At the same time that the petition for administrative review is filed, the petitioner shall:

(i) Serve a copy of the petition on the designated representative or authorized account representative under paragraph (a)(1) and (2) of this section (unless the designated representative or authorized account representative is the petitioner) and the Administrator; and

(ii) Mail a notice of the petition to the persons entitled to written notice under § 72.65(b)(1)(ii), (iii), and (iv) of this chapter.

(c) The petition for administrative review under this part shall state with specificity:

(1) Each material factual and legal issue alleged to be in dispute and any such factual issue for which an evidentiary hearing is sought;

(2) A clear and concise statement of the nature and scope of the interest of the petitioner;

(3) A clear and concise brief in support of the petition, explaining why the factual or legal issues are material and, if an evidentiary hearing is requested, why direct and cross-examination of witnesses is necessary to resolve such factual issues;

(4) If an evidentiary hearing is requested, the time estimated to be necessary for an evidentiary hearing;

(5) If an evidentiary hearing is requested, a certified statement that, in the event of an evidentiary hearing, and without cost or expense to any other party, any of the following persons shall be available to appear and testify:

(i) The petitioner; and

(ii) Any officer, director, employee, consultant, or agent of the petitioner.

(6) Specific references to the contested portions of the decision;

(7) Any revised or alternative action of the Administrator sought by the petitioner as necessary to implement the requirements, purposes, or policies of title IV of the Act; and

(8) Identification of any portion of the decision that the petitioner believes should be stayed pending resolution of the appeal.

(d) In no event shall a petition for administrative review be filed, or review be available under this part, with regard to:

(1) A decision under part 73 of this chapter to which the claim of error procedure applies, but for which no claim of error notification was submitted, under part 73 of this chapter;

(2) Any provision or requirement of parts 72, 73, 75, or 77 of this chapter and regulations implementing sections 407 and 410 of the Act, including any standard requirement under § 72.9 of this chapter and any emissions monitoring or reporting requirements under part 75 of this chapter;

(3) The reliance by the Administrator on a certificate of representation submitted by a designated representative or a certification statement submitted by an authorized account representative under the Acid Rain Program; and

(4) Actions of the Administrator under sections 112(r), 113, 114, 120, 301, and 303 of the Act.

§ 78.4 Filings.

(a) All original filings made under this part shall be signed by the person making the filing or by an attorney or authorized representative. Any filings on behalf of owners and operators of an affected unit or affected source shall be signed by the designated representative. Any filings on behalf of persons with an interest in allowances in a general account shall be signed by the authorized account representative. The name, address, telephone number, and

facsimile number of the person making the filing shall be provided with the filing.

(b)(1) All data and information referred to, or in any way relied upon, in any filings made under this part shall be included in full and may not be incorporated by reference, unless the data or information is contained in the administrative record for the decision being appealed.

(2) Notwithstanding paragraph (b)(1) of this section, State or federal statutes, regulations, and judicial decisions published in a national reporter system, officially issued EPA documents of general applicability, and any other publicly and generally available reference material may be incorporated by reference. Any person incorporating such materials by reference shall provide copies of the materials as instructed by the Environmental Appeals Board or the Presiding Officer.

(3) If any part of any filing is in a foreign language, it shall be accompanied by an English translation verified by the person making the translation, under oath, to be complete and accurate, together with the name, address, and a brief statement of the qualifications of the person making the translation. Translations filed of material originally produced in a foreign language shall be accompanied by copies of the original material.

(4) Where relevant data or information is contained in a document also containing irrelevant matter, either the irrelevant matter shall be deleted or an index to the relevant portions of the document shall be included in the document.

(c)(1) Failure to comply with the requirements of this section or any other requirement in this part may result in the noncomplying portions of the filing being excluded from consideration. If the Environmental Appeals Board or the Presiding Officer determines on motion by any party or *sua sponte* that a filing fails to meet any requirement of this part, the Environmental Appeals Board or Presiding Officer may return the filing, together with a reference to the applicable requirements on which the determination is based. A person whose filing has been rejected has 7 days, from the date the returned filing is mailed, to correct the filing in conformance with this part and refile it, unless the Environmental Appeals Board or Presiding Officer authorizes a longer time based on good cause shown.

(2) The making of a filing shall not mean or imply that the filing, in fact, meets all applicable requirements, that the filing contains reasonable grounds for the action requested, or that the action requested is in accordance with law.

(d) An original and two copies of any written filing under this part shall be filed with the Environmental Appeals Board unless a proceeding is pending before a Presiding Officer, in which case they shall be filed with the Hearing Clerk (except as provided under § 78.19(d)) of this part.

(e)(1) The party making any filing in a proceeding under this part shall also serve a copy of the filing on each party to the proceeding, or, with regard to a petition for administrative review, on the persons specified in § 78.3(b)(3) of this part.

(2) Every filing made under this part shall be accompanied by a certificate of service citing the date, place, time, and manner of service and the names of the persons served.

(f) The Hearing Clerk will maintain and furnish, to any person upon request, the official service list containing the name, service address, telephone, and facsimile numbers of each party to a proceeding under this part and his or her attorney or duly authorized representative.

(g) Affidavits filed under this part shall be made on personal knowledge and belief, set forth only those facts that are admissible into evidence under § 78.5 of this part, and show affirmatively that the affiant is competent to testify to the matters stated therein.

§ 78.5 Limitation on filing or presenting new evidence and raising new issues.

(a) Where there was an opportunity for public comment, or to submit a claim of error notification, prior to the decision that is subject to appeal, no evidence shall be filed or presented, and no issues raised, in a proceeding under this part that were not filed, presented, or raised during the public comment period, absent a showing of good cause explaining the party's failure to do so during the public comment period or in the claim of error notification. Good cause shall include any instance where the party seeking to file or present new evidence or raise a new issue shows that the evidence could not have reasonably been ascertained, filed, or presented, the issue could not have reasonably been ascertained or raised, or that the materiality of the new evidence or issue could not have reasonably been anticipated, prior to the close of the public comment period or the period for submitting a claim of error notification.

(b) If an evidentiary hearing is granted, no evidence shall be filed or presented on questions of law or policy or on matters not subject to challenge in the evidentiary hearing.

§ 78.6 Action on petition for administrative review.

(a) If no evidentiary hearing concerning the petition for review is requested or is to be held, the Environmental Appeals Board will issue an order under § 78.20(c) of this part.

(b)(1) The Environmental Appeals Board may grant a request for an evidentiary hearing, or schedule an evidentiary hearing *sua sponte*, if the Environmental Appeals Board finds that there are disputed issues of fact material to contested portions of the decision and determines, in its discretion, that an opportunity for direct- and cross-examination of witnesses may be necessary in order to resolve these factual issues.

(2) To the extent the Environmental Appeals Board grants a request for an evidentiary hearing, in whole or in part, it will:

(i) Identify the portions of the decision that have been contested, and the disputed factual issues that have been raised by the petitioner with regard to which the evidentiary hearing has been granted; and

(ii) Refer the disputed factual issues to the Chief Administrative Law Judge for decision and, in its discretion, may also refer all or a portion of the remaining legal, policy, or factual issues to the Chief Administrative Law Judge for decision.

(3)(i) After issues are referred to the Chief Administrative Law Judge, he or she will designate an Administrative Law Judge as Presiding Officer to conduct the evidentiary hearing.

(ii) Notwithstanding paragraph (b)(3)(i) of this section, if all parties waive in writing their right to have an Administrative Law Judge designated as the Presiding Officer, the Administrator may designate a lawyer permanently or temporarily employed by EPA and without any prior connection with the proceeding to serve as Presiding Officer.

§ 78.7 Stays of contested Acid Rain requirements pending appeal.

(a) A contested decision of the Administrator may be stayed, in whole or in part consistent with paragraph (b) of this section, by the Environmental Appeals Board or the Presiding Officer upon request of a party during a proceeding under this part only to the extent necessary to prevent irreparable injury pending final agency action.

(b) The following requirements shall in no event be stayed due to any appeal of a decision of the Administrator and shall be fully effective and enforceable:

(1) The allowance allocations for any year during which the appeal proceeding is pending or is being conducted;

(2) Any standard requirements under § 72.9 of this chapter;

(3) The emissions monitoring and reporting requirements applicable to the affected units at an affected source under part 75 of this chapter;

(4) Uncontested provisions of the decision; and

(5) The terms of a certificate of representation submitted by a designated representative under part 72, subpart B of this chapter or a certification statement submitted by an authorized account representative under part 73, subpart C of this chapter.

(c) The permit shield under § 72.51 of this chapter shall continue to be in effect.

(d) The Environmental Appeals Board or Presiding Officer shall specify which provisions of the decision shall be stayed.

§ 78.8 Consolidation and severance of appeals proceedings.

(a) The Environmental Appeals Board or Presiding Officer has the discretion to consolidate, in whole or in part, two or more proceedings under this part whenever it appears that a joint proceeding on any or all of the matters at issue in the proceedings will be in the interest of justice, will expedite or simplify consideration of the issues, and will not prejudice any party. Consolidation of proceedings under this paragraph (a) will not affect the right of any party to raise issues that might have been raised had there been no consolidation.

(b) The Environmental Appeals Board or Presiding Officer has the discretion to sever issues or parties from a proceeding under this part whenever it appears that separate proceedings will be in the interest of justice, will expedite or simplify consideration of the issues, and will not prejudice any party.

§ 78.9 Notice of the filing of petition for administrative review.

The Administrator will publish in the **Federal Register** a notice stating that a petition for administrative review of a decision of the Administrator has been filed and specifying any request in the petition for an evidentiary hearing.

§ 78.10 Ex parte communications during pendency of a hearing.

(a)(1) No party or interested person outside EPA, representative of a party or interested person, or member of the EPA trial staff shall make, or knowingly cause to be made, to any member of the decisional body an *ex parte* communication on the merits of a proceeding under this part.

(2) No member of the decisional body shall make, or knowingly cause to be made, to any party or interested person outside EPA, representative of a party or interested person, or member of the EPA trial staff, an *ex parte* communication on the merits of any proceeding under this part.

(3) A member of the decisional body who receives, makes, or knowingly causes to be made an *ex parte* communication prohibited by this paragraph shall file with the Environmental Appeals Board (or, if the proceeding is pending before an Administrative Law Judge, with the Hearing Clerk) for inclusion in the record of the proceeding under this part any such written *ex parte* communication and memoranda stating the substance of any such oral *ex parte* communication.

(b) Whenever any member of the decisional body receives an *ex parte* communication made, or knowingly caused to be made by a party or representative of a party to a proceeding under this part, the person presiding over the proceedings then in progress may, to the extent consistent with justice, require the party to show good cause why its claim or interest in the proceedings should not be dismissed, denied, disregarded, or otherwise adversely affected on account of these *ex parte* communications.

(c) The prohibitions of paragraph (a) of this section shall begin to apply upon publication by the Administrator of the notice of the filing of a petition under § 78.9 of this part. This prohibition terminates on the date of final agency action.

§ 78.11 Intervenors.

(a) Within 30 days after notice is given under § 78.9 of this part that the petition for administrative review has been filed, any person listed in § 78.3(a) of this part may file a motion for leave to intervene in the proceeding. A motion for leave to intervene under this section shall set forth the grounds for the proposed intervention and may respond to the petition for administrative review. Late motions to intervene may be granted only for good cause shown.

(b) The Environmental Appeals Board of Presiding Officer will grant a motion to intervene only upon an express finding that:

(1) The motion to intervene raises matters relevant to the factual or legal issues to be reviewed;

(2) The intervenor consented to be bound by all stipulations previously entered into by the existing parties, and all orders previously issued, in the proceeding; and

(3) The intervention will promote the interests of justice and will not cause undue delay or prejudice to the rights of the existing parties.

§ 78.12 Standard of review.

(a) On appeal of a decision of the Administrator prior to which there was an opportunity for public comment, or to submit a claim of error notification:

(1) Except as provided under paragraph (a)(2) of this section, the petitioner shall have the burden of going forward and of persuasion to show that a finding of fact or conclusion of law underlying the decision is clearly erroneous or that an exercise of discretion or policy determination underlying the decision is arbitrary and capricious or otherwise warrants review.

(2) The owners and operators of the source or unit involved shall have the burden of persuasion that an Acid Rain permit or a written exemption under §§ 72.7 or 72.8 of this chapter was properly issued or should be issued.

(b) On appeal of a decision of the Administrator not covered by paragraph (a) of this section, the Administrator shall have the burden of going forward to show the rational basis for the decision. The petitioner shall have the burden of persuasion to show that a finding of fact or conclusion of law underlying the decision is clearly erroneous or that an exercise of discretion or policy determination underlying the decision is arbitrary and capricious or otherwise warrants review.

§ 78.13 Scheduling orders and pre-hearing conferences.

(a) If a request for an evidentiary hearing is granted, the Presiding Officer will issue an order scheduling the following:

(1) The filing by each party of a narrative statement of position on each factual issue in controversy.

(2) The identification of any witness that a party expects to call and of any written testimony, documents, papers, exhibits, or other materials that a party expects to introduce into evidence. At the request of the Presiding Officer, the party shall include a brief narrative summary of any witness' expected testimony and of any such materials.

(3) The filing of written testimony, in accordance with § 78.14(b) of this part, and other evidence in support of a narrative statement.

(4) The filing of any motions by any party, including motions for the

production of documentation, data, or other information material to the disputed facts to be addressed at the hearing.

(b) The Presiding Officer may also, on motion or *sua sponte*, schedule one or more pre-hearing conferences on the record to address any of the following:

(1) Simplification, clarification, amplification, or limitation of the issues.

(2) Admissions and stipulations of facts and determinations of the genuineness of documents.

(3) Objections to the introduction into evidence at the hearing of any written testimony or other submissions proposed by a party; *provided* that at any time before the end of the hearing, any party may make, and the Presiding Officer may consider and rule upon, a motion to strike testimony or other evidence (other than evidence included in the administrative record (if any) under § 72.63 of this chapter) on the grounds of relevance, competency, or materiality.

(4) Taking official notice of any matters.

(5) Grouping of parties with substantially similar interests to eliminate redundant evidence, motions, objections, and briefs.

(6) Such other matters that may expedite the hearing or aid in the disposition of matters in dispute.

(c) The Presiding Officer will issue an order (which may be in the form of a transcript) reciting the actions taken at any pre-hearing conferences, setting the schedule for any hearing, and stating any areas of factual and legal agreement and disagreement and the methods and procedures to be used in developing any evidence.

§ 78.14 Evidentiary hearing procedure.

(a) If a request for an evidentiary hearing is granted, the Presiding Officer will conduct a fair and impartial hearing on the record, take action to avoid unnecessary delay in the disposition of the proceedings, and maintain order. For theses purposes, the Presiding Officer may:

(1) Administer oaths and affirmations.

(2) Regulate the course of the hearings and prehearing conferences and govern the conduct of participants.

(3) Examine witnesses.

(4) Identify and refer issues for interlocutory decision under § 78.19 of this part.

(5) Rule on, admit, exclude, or limit evidence.

(6) Establish the time for filing motions, testimony and other written evidence, and briefs and making other filings.

(7) Rule on motions and other pending procedural matters, including but not limited to motions for summary disposition in accordance with § 78.15 of this part.

(8) Order that the hearing be conducted in stages whenever the number of parties is large or the issues are numerous and complex.

(9) Allow direct and cross-examination of witnesses only to the extent the Presiding Officer determines that such direct and cross-examination may be necessary to resolve disputed issues of material fact; *provided* that no direct or cross-examination shall be allowed on questions of law or policy or regarding matters that are not subject to challenge in the evidentiary hearing.

(10) Limit public access to the hearing where necessary to protect confidential business information. The Presiding Officer will provide written notice of the hearing to the parties, and where the hearing will be open to the public, notice in the **Federal Register** no later than 15 days prior to commencement of the hearings.

(11) Take any other action not inconsistent with the provisions of this part for the maintenance of order at the hearing and for the expeditious, fair and impartial conduct of the proceeding.

(b) All direct and rebuttal testimony at an evidentiary hearing shall be filed in written form, unless, upon motion and good cause shown, the Presiding Officer, in his or her discretion, determines that oral presentation of such evidence on any particular factual issue will materially assist in the efficient resolution of the issue.

(c)(1) The Presiding Officer will admit all evidence that is not irrelevant, immaterial, unduly repetitious, or otherwise unreliable or of little probative value. Evidence relating to settlement that would be excluded in the federal courts under Rule 408 of the Federal Rules of Evidence shall not be admissible.

(2) Whenever any evidence or testimony is excluded by the Presiding Officer as inadmissible, all such evidence will remain a part of the record as an offer of proof. The party seeking the admission of oral testimony may make an offer of proof by means of a brief statement on the record describing the testimony excluded.

(3) When two or more parties have substantially similar interests and positions, the Presiding Officer may limit the number of attorneys or authorized representatives who will be permitted to examine witnesses and to make and argue motions and objections on behalf of those parties.

(4) Rulings of the Presiding Officer on the admissibility of evidence or testimony, the propriety of direct and cross-examination, and other procedural matters will appear in the record of the hearing and control further proceedings unless reversed by the Presiding Officer or as a result of an interlocutory appeal taken under § 78.19 of this part.

(5) All objections shall be made promptly or be deemed waived; *provided* that parties shall be presumed to have taken exception to an adverse ruling. No objection shall be deemed waived by further participation in the hearing.

§ 78.15 Motions in evidentiary hearings.

(a) Any party may make a motion to the Presiding Officer on any matter relating to the evidentiary hearing in accordance with the scheduling orders issued under § 78.13 of this part. All motions shall be in writing and served as provided in § 78.4 of this part, except those made on the record during an oral hearing before the Presiding Officer.

(b) Any party may make a motion for a summary disposition in its favor on any factual issue on the basis that there is no genuine issue of material fact. When a motion for summary disposition is made and supported, any party opposing the motion may not rest upon mere allegations or denials, but must show, by affidavit or by other materials subject to consideration by the Presiding Officer, that there is a genuine issue of material fact.

(c) Within 10 days after a motion made on the record or service of any written motion, any party may file a response to the motion. The time for response may be shortened or extended by the Presiding Officer for good cause shown.

(d) The Presiding Officer may schedule an oral argument and call for the filing of briefs on any motion. The Presiding Officer will rule on the motion within a reasonable time after the date that responses to the motion may be filed under paragraph (c) of this section and that any oral argument or filing of briefs is completed.

(e) If all factual issues are decided by summary disposition prior to the hearing, no hearing will be held and the Presiding Officer will issue a proposed decision under § 78.18 of this part. If a summary disposition is denied or if partial summary disposition is granted, the hearing shall proceed on the remaining issues.

§ 78.16 Record of appeal proceeding.

(a) The proposed decision issued by the Presiding Officer, transcripts of oral hearings or oral arguments, written

direct and rebuttal testimony, and any other written materials of any kind filed in the proceeding will be part of the record and will be available to the public in the office of the Hearing Clerk, subject to the requirements of part 2 of this chapter.

(b) Hearings and oral arguments shall be recorded as specified by the Presiding Officer, and thereupon transcribed. After the hearing or oral argument, the reporter will certify and file with the Hearing Clerk.

(1) The original transcript; and

(2) Any exhibits received or offered into evidence at the hearing.

(c) The Hearing Clerk will promptly give written notice to the parties when any transcript is available. Any party that desires a copy of the transcript may obtain a copy upon payment of costs.

(d) The Presiding Officer will allow witnesses, parties, and their counsel or representatives:

(1) Up to 7 days from issuance of the notice under paragraph (c) of this section in order to file written proposed corrections of the transcript necessary to correct errors made in the transcribing; and

(2) Up to 7 days from the submission of the corrections in order to file objections to the proposed corrections.

(e) The Presiding Officer will determine which, if any, corrections should be made to the transcript and incorporate them into the record.

§ 78.17 Proposed findings and conclusions and supporting brief.

Within 45 days after issuance of a notice under § 78.16(c) of this part that the complete transcript of the evidentiary hearing is available, any party may file with the Hearing Clerk proposed findings and conclusions on the issues referred to the Presiding Officer and a brief in support thereof. Briefs shall contain appropriate references to the record. The Presiding Officer, for good cause shown, may shorten or extend the time for filing and may allow reply briefs.

§ 78.18 Proposed decision.

(a) The Presiding Officer will review and evaluate the record, including the proposed findings and conclusions and any briefs filed by the parties, and issue a proposed decision on the factual, policy, and legal issues referred by the Environmental Appeals Board for decision under § 78.6(b)(2)(ii) of this part, accompanied by findings of fact and proposed conclusions of law, as appropriate, within a reasonable time after the evidentiary hearing is completed. The Hearing Clerk will promptly serve copies of the proposed decision on all parties and on the Environmental Appeals Board.

(b) The proposed decision of the Presiding Officer shall become the final agency action under section 307 of the Act 30 days after service unless within that time:

(1) A party files objections with the Environmental Appeals Board pursuant to § 78.20(a) of this part, or

(2) The Environmental Appeals Board *sua sponte* files a notice that it will review the decision under § 78.20(b) of this part.

§ 78.19 Interlocutory appeal.

(a) Interlocutory appeal from orders or rulings of the Presiding Officer made during the course of a proceeding may be taken if the Presiding Officer certifies those orders or rulings to the Environmental Appeals Board for interlocutory appeal on the record. Any requests to the Presiding Officer to certify an interlocutory appeal shall be filed within 10 days of notice of the order or ruling and shall state briefly the grounds for the request.

(b)(1) Within 15 days of the filing of any request for interlocutory appeal, the Presiding Officer may certify an order or ruling for interlocutory appeal to the Environmental Appeals Board if:

(i) The order or ruling involves an important question on which there is substantial ground for difference of opinion, and

(ii) Either:

(A) An immediate appeal of the order or ruling will materially advance the ultimate completion of the proceeding, or

(B) A review after the proceeding is completed will be inadequate or ineffective.

(2) If the Presiding Officer takes no action within 15 days of the filing of a request for interlocutory appeal, the request shall be automatically dismissed without prejudice.

(c) If the Presiding Officer grants certification, the Environmental Appeals Board may accept or decline the interlocutory appeal within 30 days of certification. If the Environmental Appeals Board decides that certification was improperly granted, it will decline to hear the interlocutory appeal. If the Environmental Appeals Board takes no action within 30 days of certification, the interlocutory appeal shall be automatically dismissed without prejudice.

(d) If the Presiding Officer declines to certify an order or ruling for an interlocutory appeal, the order or ruling may be reviewed by the Environmental Appeals Board only upon an appeal of the proposed decision following completion of the proceedings before the Presiding Officer, except when the Environmental Appeals Board determines, upon motion of a party and in exceptional circumstances, that to delay review would not be in the public interest. Such motion shall be filed with Environmental Appeals Board within 5 days after the earlier of automatic dismissal of the request for interlocutory appeal or receipt by the party of notification that the Presiding Officer declines to certify an order or ruling for interlocutory appeal.

(e) The failure of a party to request an interlocutory appeal shall not prevent an appeal of an order or ruling as part of an appeal of a proposed decision under § 78.20 of this part.

§ 78.20 Appeal of decision of Administrator or proposed decision to the Environmental Appeals Board.

(a) Within 30 days after the issuance of a proposed decision by a Presiding Officer under this part, any party may appeal any matter set forth in the proposed decision, or any other order or ruling made during the proceeding to which the party objected during the proceeding before the Presiding Officer, by filing an objection with the Environmental Appeals Board. On appeal of an order, ruling, or proposed decision of a Presiding Officer:

(1) The party filing the objection shall have the burden of going forward to show that the order, ruling, or proposed decision is based on a finding of fact or conclusion of law that is clearly erroneous; or a policy determination or exercise of discretion that is arbitrary and capricious or otherwise warrants review; and

(2) The petitioner or the owners and operators shall have the burden of persuasion, as set forth in § 78.12(a) (1) and (2) of this part.

(b) Within 30 days after issuance of a proposed decision of a Presiding Officer, the Environmental Appeals Board may issue *sua sponte* in its discretion a notice of intent to review such proposed decision. The Environmental Appeals Board will serve such notice upon all parties to the proceeding.

(c) Within a reasonable time following the filing of a petition for administrative review of a decision of the Administrator under § 78.3 of this part, or, if any issues raised by such petition are referred to the Presiding Officer, the filing of objections under paragraph (a) of this section or the issuance of a notice of intent to review under paragraph (b) of this section, the Environmental Appeals Board will issue an order affirming, reversing, modifying, or

remanding the decision or proposed decision, as appropriate. Prior to issuing this order, the Environmental Appeals Board may provide an opportunity for parties to file additional briefs.

(d) If the Environmental Appeals Board issues an order affirming, reversing, or modifying the decision of the Administrator, then the decision as supplemented or changed by the order, shall be final agency action.

(e) If the Environmental Appeals Board issues an order affirming, reversing, or modifying the proposed decision, the proposed decision, as supplemented or changed by the order, shall be final agency action.

(f) If the Environmental Appeals Board issues an order remanding the proceeding, then final agency action occurs upon completion of the remanded proceeding, including any appeals to the Environmental Appeals Board in the remanded proceeding.

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Part III

Environmental Protection Agency

40 CFR Part 51

Criteria and Procedures for Determining Conformity to Transportation Plans; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 51

[AMS–FRL–4550–7]

Criteria and Procedures for Determining Conformity to State or Federal Implementation Plans of Transportation Plans, Programs, and Projects Funded or Approved Under Title 23 U.S.C. or the Federal Transit Act

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of proposed rulemaking.

SUMMARY: EPA proposes criteria and procedures for determining that transportation plans, programs, and projects which are funded or approved under title 23 U.S.C. or the Federal Transit Act conform with State or Federal air quality implementation plans. This action is required under section 176(c)(4) of the Clean Air Act Amendments of 1990.

Conformity to an implementation plan is defined in the Clean Air Act as conformity to an implementation plan's purpose of eliminating or reducing the severity and number of violations of the national ambient air quality standards and achieving expeditious attainment of such standards. Federal activities may not cause or contribute to new violations of air quality standards, exacerbate existing violations, or interfere with the timely attainment or interim emission reductions towards attainment. This proposal would establish the process by which the Federal Highway Administration and the Federal Transit Administration of the United States Department of Transportation and metropolitan planning organizations determine conformity of highway and transit projects.

DATES: Written comments on this notice will be accepted for 60 days until March 12, 1993. EPA will conduct three public hearings on this proposal beginning at 10:30 a.m. on January 29, 1993 in Washington, DC; February 5, 1993 in California; and February 10, 1993 in Missouri. The hearings will continue throughout the day until all testimony has been presented.

ADDRESSES: Interested parties may submit written comments (in duplicate, if possible) to: Air Docket Section (LE–131), U.S. Environmental Protection Agency, Attention: Docket No. A–92–21, 401 M Street, SW., Washington, DC 20460. (Those desiring notification of receipt of comments must include a self-addressed, stamped postcard.)

Public hearings will be held in Washington, DC, at the Ramada Renaissance Techworld, 999 9th St. NW.; in Los Angeles, California at the Sheraton Grand Hotel, 333 South Figueroa; and in St. Louis, Missouri at the Stouffer Concourse Hotel, 9801 Natural Bridge Road.

Materials relevant to this proposal have been placed in Public Docket A–92–21 by EPA. The docket is located at the above address in room M–1500 Waterside Mall (ground floor) and may be inspected from 8:30 a.m. to 12 p.m. and from 1:30 p.m. to 3:30 p.m., Monday through Friday.

FOR FURTHER INFORMATION CONTACT: Kathryn Sargeant, Emission Control Strategies Branch, Emission Planning and Strategies Division, U.S. Environmental Protection Agency, 2565 Plymouth Road, Ann Arbor, MI 48105. Telephone: (313) 668–4441.

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I. Authority

Authority for the actions proposed in this notice is granted to EPA and DOT by section 176(c) of the Clean Air Act as amended (42 U.S.C. 7521(a)).

II. Background of Proposed Rule

A. Overview of the Transportation Planning Process

The joint Federal Highway Administration (FHWA)/Federal Transit Administration (FTA) urban transportation planning regulations codified at 23 CFR 450 require all urban areas with a population of more than 50,000 to have a continuous, cooperative, and comprehensive (3C) transportation planning process. The 3C planning process forms the basis for all local and State decisions involving Federal highway and transit assistance in urban areas. The planning process is generally carried out by State governments, metropolitan planning organizations (MPOs), and transit operators. The designation and membership of MPOs are decided by the units of local government and the State governor.

The urban transportation planning process requires each urbanized area to develop a transportation plan and a transportation improvement program (TIP). The MPO must approve the plan, and the MPO and the State governor must approve the TIP in order to receive Federal funds for transportation projects.

The transportation plan is a long-range plan describing policies, strategies, and facilities to accommodate current and future travel demands and to make more efficient use of the existing transportation system. It identifies facilities which should function as an integrated metropolitan transportation system, giving emphasis to those facilities that serve important national and regional transportation functions.

The TIP is a more specific program of transportation projects that are consistent with the transportation plan. The TIP includes a priority list of projects and project segments to be carried out within each three-year period after the initial adoption of the TIP. The TIP is developed by the MPO, in cooperation with the State and affected transit operators, and must be updated at least once every two years.

In addition to the transportation plans and TIPs, each State must annually prepare and submit to DOT a statewide program of projects which the State proposes for Federal assistance. FHWA and FTA generally require that the projects for urbanized areas be drawn from each area's TIP.

The approval actions taken by FHWA and FTA are on the statewide TIPs.

Prior to taking these actions on the metropolitan portion(s) of the statewide TIP, FHWA and FTA must find that (1) the metropolitan TIP is based on a 3C planning process carried on cooperatively by the States and local communities in accordance with the provisions of 23 U.S.C. 134 and 135 and the Federal Transit Act; and (2) in nonattainment areas, the metropolitan TIP conforms with the implementation plan and priority has been given to transportation control measures contained in the implementation plan in accordance with procedures in this conformity regulation.

Before a federally assisted transportation project is actually implemented, it must go through project development/analysis of alternatives and final design phases. The project development/analysis of alternatives phase gathers more detailed information on the impacts of several potential project alternatives. The environmental, social, and economic impacts of the alternatives are analyzed, and the environmental assessments and impact statements required by the National Environmental Policy Act (NEPA) are prepared. After the public has had an opportunity for review and comment, a final NEPA document is prepared. Although NEPA requires the consideration of reasonable alternatives which would avoid or minimize adverse environmental impacts, NEPA does not require the preferred alternative to be chosen solely on the basis of environmental impacts. The final environmental document must be approved by FHWA or FTA.

Once the environmental process is completed, the final design is developed, construction plans, specifications, and estimates are developed, cost estimates are refined, and rights-of-way are acquired. The project may then proceed to construction.

B. Overview of the Air Quality Planning Process

The Clean Air Act (CAA) as amended in 1990 (Pub. L. 101–549; 42 U.S.C. 7401, et seq.) requires each State to submit to EPA a State implementation plan (SIP). The SIP is an air quality management plan which contains rules and regulations for air pollution sources under State control and a demonstration that the State will attain the national ambient air quality standards (NAAQS) by the dates set forth in the CAA.

State air quality agencies have the primary responsibility for preparing the SIP. However, State and local air quality and transportation agencies must work together to develop SIP strategies for transportation that are realistic, fundable, and effective in reducing emissions. The State SIP development process involves public hearings, and the SIP must be supported by adequate State legislation before the governor submits it to EPA.

Under section 107(d) of the CAA, all areas of the country are designated attainment, nonattainment, or unclassifiable with respect to the NAAQS. SIPs for most nonattainment areas must contain an inventory of current NAAQS pollutant emissions, as well as air quality modeling which demonstrates that given certain assumptions about population growth, economic growth, and growth in vehicle miles traveled (VMT), the SIP's control measures will result by a certain date in a level of emissions which is in attainment with the NAAQS. The attainment demonstration establishes a level of allowable emissions, which EPA calls an emissions budget. Attainment demonstrations for areas designated nonattainment for particulate matter less than ten microns in diameter (PM_{10}) are already due to EPA, and carbon monoxide (CO) nonattainment areas which are classified as serious or moderate with design value above 12.7 parts per million must submit attainment demonstrations by November 15, 1992. Ozone nonattainment areas which are classified as serious, severe, or extreme must submit attainment demonstrations by November 15, 1994. Moderate ozone nonattainment areas must submit such demonstrations by November 15, 1993, unless they are using regional airshed modeling, in which case they have until November 15, 1994.

In addition to the attainment demonstration, SIPs for most ozone nonattainment areas must demonstrate reasonable further progress (RFP) toward attainment for certain milestone years. Moderate, serious, severe, and extreme ozone areas must demonstrate in the SIP that emissions of volatile organic compounds (VOC) will be reduced by 15% from 1990 baseline emissions by 1996. (Certain adjustments and exclusions apply.) Serious, severe, and extreme ozone areas must also demonstrate that in milestone years occurring every three years from 1996 until the attainment date, VOC will be reduced from baseline emissions by an average of three percent per year. (Nitrogen oxides emissions reductions may in some cases substitute for all or a part of the required VOC emissions reductions.) PM_{10} nonattainment areas must also submit SIPs with quantitative emission reduction milestones which must be achieved every three years. The RFP requirements in effect create an emissions budget for each milestone year, in addition to the budget that applies for the attainment year.

If a State fails to make an SIP submission, if an SIP submission is disapproved by EPA, or if a requirement in an approved SIP is not being implemented, EPA may (and in some cases must) apply highway funding sanctions. These highway sanctions would prohibit DOT from approving projects or awarding grants in the affected nonattainment area, unless the project or grant was to improve a demonstrated safety problem, was one of several exempt types listed in the CAA, or was found to reduce air pollution problems by the EPA Administrator. Within two years after an EPA finding of State failure or SIP disapproval, EPA would be required to promulgate a Federal implementation plan (FIP) which would correct the SIP's deficiencies.

EPA's document "State Implementation Plans; General Preamble for the Implementation of title I of the Clean Air Act Amendments of 1990" (57 FR 13498, April 16, 1992) provides more information on the SIP process and the 1990 CAA requirements.

C. History of Conformity

Conformity provisions first appeared in the Clean Air Act Amendments of 1977 (Pub. L. 95–95). Although these provisions did not define conformity, they provided that no Federal department "shall (1) engage in, (2) support in any way or provide financial assistance for, (3) license or permit, or (4) approve any activity which does not conform to a plan [State implementation plan] after it has been approved or promulgated." Assurance of conformity was an affirmative responsibility of the head of each Federal agency. In addition, no MPO could approve any transportation project, program, or plan which did not conform to a State or Federal implementation plan.

Following enactment of the 1977 Amendments, the Department of Transportation (DOT) consulted with EPA to develop conformity procedures for programs administered by FHWA and the Urban Mass Transportation Administration (now FTA). The June 1978 Memorandum of Understanding Regarding Integration of Transportation and Air Quality Planning provided EPA an opportunity to jointly review and comment on the conformity of transportation plans and TIPs.

In April 1980, EPA published an advance notice of proposed rulemaking on conformity (45 FR 21590, April 1,

1980). EPA maintained that the Congressional intent of CAA section 176(c) was to prevent Federal actions from causing a delay in the attainment or maintenance of the NAAQS. However, no further rulemaking action was taken.

In June 1980 EPA and DOT jointly issued a guidance document entitled "Procedures for Conformance of Transportation Plans, Programs and Projects with Clean Air Act State Implementation Plans." This guidance established that in nonattainment and maintenance areas (areas experiencing NAAQS violations and required to develop air quality maintenance plans under 40 CFR part 51, subpart D), conformity determinations must be documented as a necessary element of all certifications, TIP reviews, and EIS findings. It was necessary to make certifications that the planning process had been conducted according to the 3C process and consistent with Clean Air Act requirements.

Transportation plans and programs were considered to conform with the SIP if they did not adversely affect the transportation control measures (TCMs) in the SIP, and if they contributed to reasonable progress in implementing those TCMs. A transportation project would conform if it were a TCM from the SIP, came from a conforming TIP, or did not adversely affect the TCMs in the SIP.

Subsequently, DOT developed and issued an interim final rule (46 FR 8426, January 26, 1981) based upon the joint guidance. DOT established this rule to meet its obligations under section 176(c) of the CAA, and the rule was put into effect immediately upon publication. It amended 23 CFR part 770 (FHWA Air Quality Guidelines) and added 49 CFR part 623 (UMTA Air Quality Conformity and Priority Procedures).

The rule used the joint guidance's definition of conformity, interpreting conformity in the context of TCMs rather than emissions budgets or air quality analysis. Compliance with the conformity requirements was to be demonstrated as part of the planning and NEPA processes.

D. Conformity Under the Clean Air Act Amendments of 1990

The Clean Air Act Amendments of 1990 expand the scope and content of the conformity provisions by defining conformity to an implementation plan to mean conformity to the plan's purpose of eliminating or reducing the severity and number of violations of the national ambient air quality standards and achieving expeditious attainment of such standards; and that such activities will not (i) cause or contribute to any new violation of any standards in any area; (ii) increase the frequency or severity of any existing violation of any standard in any area; or (iii) delay timely attainment of any standard or any required interim emission reductions or other milestones in any area.

In addition to this general definition which applies to all Federal actions, transportation plans, programs, and projects funded under title 23 U.S.C. or the Federal Transit Act (hereinafter "transportation plans, programs, and projects") must be found to conform before they can be approved at the local level by the MPO. Transportation plans, programs, and projects also must be found to conform at the Federal level by DOT before they can be approved, accepted, or funded.

Section 176(c)(2) of the 1990 Amendments requires the expected emissions from transportation plans and TIPs to be consistent with the implementation plan's motor vehicle emission estimates and required emissions reductions. A transportation project would conform if it came from a conforming plan and TIP, or if it was demonstrated that the projected emissions from the project, when considered together with the emissions projected for the conforming transportation plan and TIP, were consistent with the emission reduction projections and schedules in the implementation plan. Finally, TIPs must provide for the timely implementation of TCMs consistent with schedules included in the implementation plan.

The Clean Air Act Amendments of 1990 therefore emphasize reconciling the estimates of emissions from transportation plans and programs with the implementation plan, rather than simply providing for the implementation of TCMs. This integration of transportation and air quality planning is intended to protect the integrity of the implementation plan by ensuring that its growth projections are not exceeded without additional measures to counterbalance the excess growth, that progress targets are achieved, and that air quality maintenance efforts are not undermined.

Once specific emissions reduction schedules are established in the implementation plan as required by sections 182 and 187 of the 1990 Amendments, conformity requires that the emissions expected from plans and TIPs be consistent with those emissions reductions in the implementation plan. Until that time, the 1990 Amendments together with the rule proposed today establish interim requirements for transportation plans and TIPs to provide for the expeditious implementation of TCMs in the applicable implementation plan, to contribute to VOC and CO emissions reductions, and to avoid any increase in PM_{10} or NO_x emissions relative to 1990 emission levels of these pollutants. In carbon monoxide (CO) nonattainment areas, transportation projects must also eliminate or reduce the severity and number of violations of the CO standards in the area substantially affected by the project.

According to section 176(c)(4), EPA must promulgate criteria and procedures for determining conformity and must require each State to submit an implementation plan revision that includes such criteria and procedures. The criteria and procedures which EPA promulgates will apply as Federal law to both Federal and local (MPO) conformity determinations. The implementation plan revisions will make conformity criteria and procedures State requirements as well. States may elect to incorporate more stringent conformity criteria and procedures in their implementation plans than are contained in the Federal rule.

Section 176(c) of the CAA applies to all departments, agencies, and instrumentalities of the Federal government. This proposal applies only to the conformity of transportation plans, programs, and projects developed, funded, or approved under title 23 U.S.C. or the Federal Transit Act. Criteria and procedures for determining the conformity of all other Federal actions, including highway and transit projects which require funding or approval from a Federal agency other than FHWA or FTA, will be promulgated in a forthcoming rule.

E. Interim EPA/DOT Conformity Guidance

On June 7, 1991, EPA and DOT jointly issued guidance for determining conformity of transportation plans, programs, and projects during the period before the final rule is promulgated. This guidance is based on the interim conformity requirements in § 176(c)(3) of the CAA.

According to the interim guidance, a transportation plan or TIP conforms if it supports the implementation plan's purpose of achieving the NAAQS; has no goals, directives, recommendations, or projects which will have adverse impacts on the implementation plan; provides for the expeditious implementation of TCMs in the implementation plan; contributes to ozone and CO emission reductions; and

does not increase the frequency or severity of existing violations of the NAAQS for which the area is designated nonattainment.

Transportation projects conform if they come from a conforming plan and TIP and, in CO nonattainment areas, if they eliminate or reduce the number and severity of CO violations. Projects which are not from a TIP (e.g., projects outside metropolitan areas but still in nonattainment areas, and projects whose design concept and scope have changed significantly since TIP adoption) conform if they do not interfere with TCMs, if they contribute to regional emissions reductions, and in CO nonattainment areas, if they reduce local CO violations.

F. Public Consultation in the Development of This Proposal

Because the Clean Air Act Amendments of 1990 significantly broadened the scope of transportation conformity, EPA involved potentially affected parties early in its process of developing conformity criteria and procedures. EPA, FHWA, and FTA jointly funded a grant to the National Association of Regional Councils (NARC), in part to establish a technical review panel which would provide a framework for education of the affected State and local agencies and coordination of their comments to EPA. The technical review panel for conformity is comprised of representatives from the affected government entities, including representatives from NARC (which represents MPOs), the American Association of State Highway and Transportation Officials, the American Public Transit Association, the State and Territorial Air Pollution Program Administrators, and the Association of Local Air Pollution Control Officials. EPA staff have by invitation attended several panel meetings.

EPA circulated concept papers to the conformity technical review panel and other interested parties, including representatives of the environmental community and the development community. EPA also hosted a roundtable discussion in Ann Arbor, Michigan in October 1991. EPA received a substantial number of comments, which are available in the docket. The agency welcomes comments from all interested parties on the contents of this specific proposal.

III. Applicability Issues

A. Geographic Applicability

EPA has heard a wide range of opinion on the legal and public policy issues associated with whether conformity must apply in areas which have been designated as attainment or unclassifiable areas continuously since initial designation, as opposed to areas that were one designated as nonattainment areas and have since been redesignated to attainment. Some MPOs in such attainment areas believe that Congress did not intend such areas to be brought under the conformity requirements; they are also concerned that the regulatory burden associated with analyzing transportation-related emissions is not justified in areas without air quality problems. Small MPOs in particular have limited staff, planning resources, and air quality modeling experience. However, some members of the environmental community are concerned that rapidly growing attainment areas that have never before been designated nonattainment may begin violating the NAAQS unless the long-range transportation and air quality planning associated with conformity is performed.

The CAA as amended in 1990 now defines conformity in section 176(c)(1)(B)(i) as meaning, among other things, that activities will not "cause or contribute to any new violation of any standard in any area." This language can be taken to imply applicability of conformity requirements to all attainment and nonattainment areas. However, some ambiguity is introduced by the section's placement within part D of the CAA, entitled "Plan Requirements for Nonattainment Areas," and by other details of the phrasing of the conformity requirement.

After extensive review of the statutory provisions and the legislative history on this issue, EPA has concluded that a reasonable, and therefore permissible, reading of section 176(c) is that it applies only to nonattainment areas and those attainment areas subject to the maintenance plans required by section 175A of the CAA, as described below. Because the statutory language itself is ambiguous, there is no clear indication on the face of section 176(c) as to where the provision should apply. EPA has therefore looked to the statute as a whole to determine the appropriate application of the provision.

EPA believes that an important piece of evidence is the placement of section 176(c) within part D of the CAA, entitled "Plan Requirements for Nonattainment Areas," and specifically within subpart 1, entitled "Nonattainment Areas in General." EPA believes that all provisions within these parts should apply only in nonattainment areas, unless the overall weight of the evidence in a given section indicates some other legislative intent. As described here, EPA can find no such intent in section 176 to apply the conformity requirement to the full universe of attainment areas.

Certain participants in the discussion on this issue have indicated that section 176(c)(1)(B)(i), which requires that Federal activities not lead to any new violation of any standard in any area, must be interpreted as applying to all areas, including all attainment areas. However, the provision can be read, within the context of EPA's interpretation of section 176(c), as applying only to all areas subject to the provision—that is, all nonattainment and (for the reasons discussed further below) maintenance areas.

Despite extensive legislative history on section 176(c), no mention is made of the areas subject to the provision. Because of the significant burden that imposing conformity requirements will have, especially on smaller areas outside large urban centers, EPA believes that Congress would have discussed the provision's applicability to all attainment areas if it intended the provision to apply there despite its location within part D.

In contrast, EPA believes that both the statutory language itself and the legislative history support application of the conformity requirement to those attainment areas subject to maintenance plans under section 175A of the CAA. Section 176(c)(4)(B)(iii) explicitly requires EPA's conformity procedures to address how conformity determinations will be made with respect to maintenance plans. Further in describing section 176(c), one of the lead sponsors of the 1990 CAA Amendments stated that "to the extent that the transportation plan includes a period that extends beyond the attainment deadline for an area, section 176(c)(1)(B)(i) also requires that mobile sources not cause violations of a NAAQS during the maintenance period" (136 Congressional Record, S16073, October 27, 1990). In addition, the Senate Committee Report indicates that "[t]he conformity determination applies to each pollutant for which an attainment or maintenance plan is required" (Senate Report 101–228, page 29). These pieces of statutory and legislative evidence lead EPA to conclude that under a reasonable, and therefore permissible, reading of section 176(c), conformity should apply in all areas subject to maintenance plans, despite the general limitation of conformity requirements to designated nonattainment areas.

Application of conformity to only nonattainment areas and maintenance areas was the approach historically taken by EPA and DOT with respect to transportation activities. EPA does not see any reason to alter this approach in light of the 1990 CAA Amendments. It is true that EPA has in the past indicated that section 176(c) might apply to attainment areas with respect to other types of Federal activities (45 FR 21590, April 1, 1980, Advance Notice of Proposed Rulemaking on section 176(c) in general). However, EPA never took any formal rulemaking action based on such a legal interpretation of section 176(c). As explained above, based on section 176(c) as amended, EPA believes that it would be reasonable to interpret section 176(c) so that conformity applies only in nonattainment and maintenance areas.

EPA believes that the section 176(c) and legislative references to "maintenance plans" and the legislative reference to "maintenance periods" refer to the maintenance plans and maintenance periods described in CAA section 175A, the preceding section of the CAA. That section refers to maintenance plans required for redesignation under the CAA as amended in 1990, and the maintenance period to be provided by such plans. Thus, under the interpretation EPA is proposing to adopt today, the conformity requirements would apply, with respect to a particular pollutant, only to (1) those areas designated nonattainment for that pollutant and (2) those areas that, while designated attainment for that pollutant, are subject to a maintenance plan required by section 175A because they had been redesignated from nonattainment to attainment under the 1990 amendments.

EPA believes therefore that maintenance areas include all areas designated nonattainment pursuant to the 1990 CAA Amendments and subsequently redesignated to attainment subject to the requirement to develop a maintenance plan under section 175A of the amended CAA. EPA proposes that all of these areas be subject to the requirements of section 176(c).

Furthermore, conformity applies pollutant-by-pollutant; for example, an area designated nonattainment only for ozone must consider ozone impacts in its conformity reviews. EPA notes that presently there are relatively few maintenance areas for the criteria pollutants for which conformity does apply.

B. Non-Federal Projects

This proposal would apply only to those projects which receive Federal funds or approval under title 23 U.S.C. or the Federal Transit Act. EPA is proposing that non-federal highway and transit projects—those which receive no Federal funding and require no Federal approvals or actions—are not subject to conformity. However, the emissions analyses required for conformity determinations on transportation plans and TIPs would be required to account for the impacts of all regionally significant non-federal projects.

In the event of a nonconformity determination, only Federally assisted or approved projects would be delayed. However, State and local officials are encouraged to review and revise the total mix of projects in order to bring the area into conformity.

The CAA is ambiguous regarding the applicability of conformity to non-federal projects. Section 176(c)(2)(C) of the CAA says that "transportation projects" must be found to conform if they are adopted or approved by an MPO or any recipient of funds designated under title 23 U.S.C. or the Federal Transit Act. This could be read to apply conformity to any transportation project approved by a recipient of DOT funds, regardless of the project's actual source of funding. Under this interpretation, all projects by State Departments of Transportation would require conformity determinations, because the State Departments of Transportation receive some DOT funds. An alternative reading is that "transportation project," which is not defined anywhere in the CAA, means a Federally funded or approved project, and the "any recipient of funds" provision is included to cover Federal projects which will be built outside the jurisdiction of any MPO. The title of section 176, "Limitations on Certain Federal Assistance," suggests that Congress intended only Federally approved or assisted projects to be affected by the provisions of section 176(c). None of the legislative history clearly indicates that non-federal projects were meant to be subject to conformity, but none of it clearly contradicts such applicability.

EPA concludes that the better reading of the ambiguous statutory language is that section 176(c) only covers projects supported in some way or approved by FHWA or FTA. This conclusion is bolstered by the reference to title 23 or Urban Mass Transportation Act funds in defining the project sponsors whose projects will be subject to the conformity requirement, which indicates that the requirement should apply only to those of their projects which are funded through such sources; applicability to projects which are approved by FHWA or FTA, even if they are not FHWA/FTA funded, follows from the general requirement for Federal actions (including approvals) to conform to the applicable implementation plan. Further, the requirement to find transportation projects in conformity is located in section 176(c)(2)(C) following the introductory words "in particular" at the end of the first paragraph of section 176(c)(2). Those words indicate that all that follows merely expands on and clarifies the preceding text. The preceding sentence in the body of section 176(c)(2) restates the obligation of Federal agencies to make conformity findings, and thus clearly applies only to Federally supported or approved projects.

In addition, the introductory paragraph of section 176(c) clearly imposes the requirements of the provision only on Federal agencies and MPOs, which are entities created by Federal law to distribute Federal monies to Federally funded transportation projects. Finally, the one piece of legislative history that appears to speak most directly to this point states that the law "clarifies what is meant by requiring that activities assisted, supported or licensed by Federal agencies 'conform to' a [SIP]" (Senate Report 101–228, page 28). These indications, coupled with the title of section 176(c) applying only to Federal assistance, lead EPA to conclude that the term "project" in section 176(c) only refers to federally supported or approved projects.

In the past, EPA has interpreted the ambiguous general language in the initial paragraph of section 176(c) as it appeared in the 1977 CAA Amendments as covering all projects approved by MPOs, whether or not they were Federally funded or approved. See, for example, Arizona Federal Implementation Plan, 56 FR 5458, 5474 (February 11, 1991). However, detailed language was added to section 176(c) in the 1990 CAA Amendments which required EPA to reanalyze this issue. Although EPA concluded that the ambiguity should be resolved in favor of covering all projects under the introductory paragraph of section 176(c) as it stood alone in 1977, EPA's review of the new detailed language added in 1990 lead EPA to conclude the opposite. As described above, on reading the section as a whole, EPA believes that section 176(c) in its entirety applies only to federally supported or approved projects.

EPA believes that applying conformity only to federally funded or approved projects will not significantly

reduce the protection of air quality, and thus is consistent with the purpose of the CAA as a whole. State governments have the power to regulate non-federal projects. Further, many regionally important highways will require Federal approvals for connections to interstate highways or under other statutes, for example, wetlands protection permits under the Clean Water Act. Finally, as explained in the next paragraph, the transportation plan and TIP will be required to compensate for any adverse impact of regional emissions from non-federal projects.

The collective impact of non-federal projects will eventually affect the conformity of transportation plans and TIPs, because Federal and non-federal projects share the "budget" of motor vehicle emissions which meets implementation plan emission reduction milestones and demonstrates attainment. Therefore, there is a practical need for transportation and air quality planners to consider the emissions impacts of regionally significant non-federal projects in making conformity determinations. As a result, EPA would require regionally significant non-federal projects to be addressed in the regional air quality analyses of plans and TIPs, although these non-federal projects would not require project-level conformity determinations.

Although it would still be possible for non-federal project sponsors to add or modify projects without additional analysis after the plan has been found to conform, the next plan would have to offset any emissions increases above the implementation plan's emissions budgets. States which are concerned about the impact of non-federal projects may, of course, extend conformity criteria and procedures to them, with no formal involvement of DOT.

C. Regional Significance

EPA's proposal would require the impacts of "regionally significant" projects to be considered in the regional emissions analyses for plans and TIPs. EPA's use of the term "regionally significant" is intended to limit emissions analysis to those projects which would have significant impacts on regional travel, emissions, and air quality. EPA believes that the emissions and air quality impacts of regionally insignificant projects can be considered de minimis in relation to the plan and TIP regional emissions analysis.

EPA is proposing that a "regionally significant" transportation facility is a facility with an arterial or higher functional classification, or any other facility regardless of functional classification that serves regional travel needs and would normally be included in the modeling for the transportation network. Regional travel needs would include, for example, access to major activity centers in the region, to transportation terminals, and to and from the area outside the region.

EPA considered several options for defining "regionally significant," including a definition only according to functional level or a quantifiable threshold such as average daily traffic. Definition solely by functional level would pose difficulties because regional significance does not correspond exactly with functional level. Some collectors could be considered regionally significant, but defining all collectors as regionally significant would increase required analysis resources to impracticable levels. (Collectors are surface streets providing land access and traffic circulation service within residential, commercial, and industrial areas.)

Definition according to a quantifiable threshold would eliminate ambiguity. However, although transportation professionals have an intuitive understanding of which facilities are regionally significant, the choice of an appropriate threshold is not obvious. Definition according to a precise threshold could prevent transportation and air quality professionals from using their best judgment in cases where a facility is clearly significant or insignificant.

The proposed definition refers to functional classification, the intuitive understanding of regional significance, and professional judgment. Therefore, EPA believes it is the most likely to include truly significant facilities and exclude insignificant facilities.

IV. Actions Covered by This Rule

This rule addresses only transportation plans, programs, and projects which are developed, funded, accepted or approved under title 23 U.S.C. or the Federal Transit Act. For such highway (FHWA) and transit (FTA) projects which also require action by other Federal agencies (e.g., wetlands permits), the other Federal agencies will not be required to do a separate air analysis. Those Federal agencies may adopt the air analysis of the lead agency, or agency with primary responsibility, in order to make a conformity determination of their own.

Highway and transit projects which need approval from other Federal agencies but which are not funded or approved by FHWA or FTA are not covered by this rule, but they will be addressed in a forthcoming proposed rule. That proposed rule will provide that satisfaction of the criteria and procedures in today's rule would be sufficient for the highway and transit aspects of such other projects also.

This rule would require DOT and the MPO to make conformity determinations in order to adopt, accept, or approve a transportation plan or TIP developed pursuant to 23 U.S.C. 134 or the Federal Transit Act.

The conformity of existing transportation plans would have to be determined within eighteen months of the date of publication of the final rule. After eighteen months, the conformity status of the existing or previous transportation plan would automatically lapse.

This rule would also require conformity determinations for highway or transit projects which are proposed to receive funding assistance and approval through the Federal-Aid Highway program or the Federal mass transit program, or which require FHWA or FTA approval for some aspect of the project. For such projects, conformity determinations would be made by DOT, based on information provided by the project sponsor.

Certain highway and transit projects which by their nature are neutral in terms of emissions impacts would be exempt from conformity determinations, including most safety projects and operating assistance to transit agencies. However, implementation of these projects must not interfere with the timely implementation of TCMs. These neutral projects are listed in § 51.373 of the proposed rule.

As defined in this proposal, the term "transit project" would specifically not encompass operational actions such as route changes, service schedule adjustments, or fare changes.

Conformity determinations on such activities would be cumbersome, and they are associated with Federal action only indirectly through general operating assistance. FTA is specifically prohibited from becoming involved in these types of local decisions (49 U.S.C. app. 1608(d)). EPA believes that FHWA and FTA do not have sufficient control over the use of general operating funds to justify conformity findings with respect to each individual use of such funds. However, conformity determinations for plans, TIPs, and some projects would be required to consider the most recent and planned transit routes, fares, tolls, and other highway and transit system operational policies as background assumptions.

EPA is aware that in some areas transit routes and policies play an important role in total regional emission

levels, and some people believe that proposed changes in transit routes and fares should be subject to conformity review. EPA believes such an approach would not be feasible if applied to all types of changes to transit system operational policies. However, EPA invites comment on what type of limited application of conformity might be appropriate.

Although changes in road or bridge tolls which do not require Federal approval could significantly affect travel on the transportation network, the agencies adjusting road or bridge tolls should have flexibility, and conformity determinations on such activities would be cumbersome. Again, the link to Federal support of such activities does not appear sufficient to justify application of § 176(c). Such changes would in any case have to be considered in background modeling assumptions.

Pre-existing projects which received final NEPA approval (a categorical exclusion, Finding of No Significant Impact, or a record of decision on a Final Environmental Impact Statement) and a final conformity determination by FHWA or FTA prior to the effective date of the final rule would need no further conformity determinations unless there were a significant change in design concept and scope or a supplemental environmental document for air quality purposes were required. Otherwise, such pre-existing projects which are subject to this rule could not be implemented without a new conformity determination consistent with the requirements of the final rule.

V. Implementation Plan Revision

Section 176(c)(4)(C) of the CAA requires each State to submit an implementation plan revision which includes criteria and procedures for assessing conformity. The CAA directs EPA to require submittal of these implementation plan revisions by November 15, 1992, which is twelve months after the final rule was to have been promulgated. Because the promulgation of the final rule has been delayed and will not even be effective by November 15, 1992, and because the implementation plan revisions cannot reasonably be prepared without the final rule, it is not possible for EPA to require States to submit implementation plan revisions by that date. Therefore, EPA is proposing that the plan revisions be submitted within twelve months of promulgation of the final rule. EPA believes it is appropriate to give the States a year to develop and submit implementation plan revisions, as Congress anticipated. The direct requirements of the final rule will apply as a matter of Federal law to Federal agencies and MPOs, and will not depend upon the completion or approval of the State plan revision. Therefore, EPA believes it is reasonable to allow the States twelve months to submit their plan revisions, as the CAA originally intended.

EPA requests comment on the acceptable forms which the criteria and procedures may take, for example, a State statute or a State agency rule binding on MPOs. EPA notes that the CAA requires the criteria and procedures to be legally enforceable, and a public hearing must be held prior to their adoption by the State.

A State may include procedures in its conformity plan revision which are more stringent than those in the final Federal rule. For example, a State may choose to apply conformity statewide, in all its attainment areas as well as nonattainment areas. The Ozone Transport Commission may also recommend to EPA the application of conformity throughout the transport region, under § 184(c) of the CAA. To apply conformity in attainment areas, States would need State authorizing legislation and would have to develop appropriate criteria and procedures. The criteria and procedures in this rule were designed for nonattainment areas.

VI. Interagency Consultation and Public Participation

A. Interagency Consultation

This rule proposes that the implementation plan revision addressing conformity shall include well-defined interagency consultation procedures. Specifically, development of the implementation plan, the transportation plan, and the TIP would require consultation between representatives of the MPOs; State and local air quality planning agencies; State and local transportation agencies; other organizations with responsibilities for developing, submitting, or implementing provisions of an implementation plan required by the CAA; and local or regional offices of the EPA, FHWA, and FTA.

EPA believes that the consultation process will be most successful if it accommodates the structure of involved organizations and addresses existing relationships. By proposing that the States develop the details of their own consultation procedures, EPA is allowing States the flexibility to tailor the consultation process so it can be most effective in each State. To ensure that the procedures are thorough and well-considered, EPA has included in the proposed rule a list of issues which States must address through the design and operation of the consultation process.

EPA is proposing interagency consultation during the development of implementation plans as well as during the development of transportation plans and TIPs because it believes the early and continuous involvement of air quality and transportation agencies is crucial. For example, consultation during the development of motor vehicle emissions budgets is necessary to insure that the budgets are reasonable and to allow the transportation community to begin adjusting its planning. In addition, transportation and air quality planning documents use interdependent assumptions and analyses. Delaying consultation until planning documents are already developed does not allow enough opportunity for meaningful exchange or settlement of disputes. Furthermore, if consultation on a conformity determination were not begun until the draft conformity determination was released, the conformity finding could be delayed and transportation activities could be disrupted pending resolution of any disagreement over the basis for the final conformity determination.

Although it is not feasible to require EPA concurrence on conformity determinations themselves, EPA recognizes the importance of reaching agreement on the methodology of the analyses supporting conformity determinations. Therefore, EPA invites comment on whether to adopt this proposal's approach of simply requiring consultation with EPA on the choice of the models and associated methodologies to be used in hot-spot analyses and regional air quality modeling, or whether EPA concurrence with these decisions should be required.

EPA invites comment on what if any consequences the implementation plan should impose if the implementation plan's consultation process is not observed by the MPO or State and local air quality agencies. The proposed rule does not specifically address this question.

Today's proposal requires that the implementation plan revision establishing consultation procedures address the process for obtaining comment on draft documents prior to adoption. EPA expects that memoranda of understanding will be developed between DOT and EPA and/or the State air quality agencies which will address how comments on proposed conformity determinations will be handled. However, EPA requests comment on whether this rule should specifically require DOT to explicitly consider

EPA's (or the State air quality agencies') comments on proposed conformity determinations and notify EPA (or State agencies) of the disposition of its comments before taking final action on the conformity determination. This would be consistent with DOT's interim final rule on conformity (46 FR 8426, January 26, 1981).

B. Public Participation

EPA would also require the conformity implementation plan revision to include procedures which would provide a reasonable opportunity for public review and comment on conformity determinations and their supporting materials prior to formal action on a conformity determination, where otherwise required by law.

Public consultation procedures for the development of plans and TIPs (which will include the conformity determination) are being developed by DOT in response to requirements in the Intermodal Surface Transportation Efficiency Act (ISTEA) (Pub. L. 102–240). Therefore, EPA is not proposing specific public consultation procedures in this rule. However, States may need to adopt public consultation procedures in their implementation plan revisions before DOT publishes the ISTEA requirements.

VII. Description of the Proposal

A. Frequency of Conformity Determinations

EPA is proposing that events which would fundamentally affect the basis of a conformity determination—specifically, changes to transportation plans, TIPs, or air quality implementation plans—would automatically trigger a requirement for a new conformity determination. However, in no case could more than three years elapse between determinations on transportation plans and TIPs. If conformity were not redetermined according to these requirements, the conformity status of the plan and TIP would automatically lapse, and projects could not be approved.

The three-year timeframe is the least frequent allowed by the CAA. However, EPA believes it will adequately ensure that if triggering events are infrequent, conformity determinations would still be periodically updated to reflect the current transportation system and the most recent model revisions and planning assumptions.

EPA believes conformity determinations should be made frequently enough to ensure that the conformity process is meaningful. At the same time, EPA believes it is important to limit the number of triggers for conformity determinations in order to preserve the stability of the transportation planning process.

EPA is proposing that all amendments to transportation plans and TIPs involving non-exempt projects would require conformity determinations for the plans and TIPs. Plans and TIPs are the focus of regional emissions analyses, so any changes to these documents must be analyzed for their impact on transportation-related emissions in the aggregate before one can be assured of continued conformity.

A new transportation plan or plan revision would also require a new conformity determination for the TIP, because the TIP's conformity is determined in the context of the areawide transportation system. Changes to the plan, which describes the predicted areawide transportation system, could change the conformity status of a TIP. A new regional emissions analysis would not necessarily be required of the TIP's conformity redetermination if it could be qualitatively demonstrated that the plan's changes would not affect the analyses in the previous TIP conformity determination. Because plan revisions can be anticipated, EPA expects that MPOs will be able to coordinate plan revisions and new TIPs so that only one conformity determination on a TIP would be necessary. EPA's proposal allows a reasonable interval of six months after a plan is amended or a new plan is adopted during which the TIP could be revised and a new conformity determination made by the MPO and DOT.

EPA is proposing that certain other events would trigger a new conformity determination on the transportation plan within eighteen months. EPA believes eighteen months allows timely consideration of new information without disrupting or unreasonably compressing the transportation planning cycle. The triggers would not apply to TIPs because new TIPs or TIP amendments, which require conformity determinations, would already be occurring every one or two years. The triggering events include publication of the final rule and an implementation plan revision which changes a transportation-related emissions budget or which adds, changes or deletes TCMs.

Publication of the final rule on transportation conformity would trigger a conformity determination for the plan, in order to ensure that the plan conforms according to the final criteria and procedures. Otherwise, it is possible that a plan found to conform immediately before the publication of the final rule would remain in effect for up to three years without its conformity being redetermined according to the requirements of the final rule.

Another proposed trigger is EPA approval of an implementation plan revision which changes a transportation-related emissions budget or which adds or deletes TCMs. Because conformity exists in reference to the implementation plan, any changes to the implementation plan's emissions budget or TCMs necessitate a new determination. If the transportation plan must be revised to conform with the implementation plan revision, EPA believes eighteen months from the implementation plan approval would allow a reasonable period of time for the revision and the new emissions analysis. If the existing emissions analysis for the current transportation plan demonstrates that the current plan is consistent with the new implementation plan budget, a conformity finding can be made for the current plan. The transportation plan would not need to be revised and a new regional emissions analysis would not be necessary. However, such an action would not renew the life of the plan for three years; emissions analysis must occur at least every three years.

EPA requests comment on whether the triggering event should be EPA approval of the implementation plan revision, or the governor's submission of the implementation plan revision to EPA. This proposal would make the trigger EPA approval, because EPA believes transportation plans should not be required to conform to an implementation plan which does not have the force of Federal law and which may still need revisions to make it approvable under the CAA. Section 176(c)(1) specifically requires conformity to "an implementation plan" after it has been approved. However, because the implementation plan revision has undergone a public consultation process prior to its submission to EPA, the content of the revision is known before EPA approval. Therefore, it would be possible to use the implementation plan revision as the basis for conformity determinations even before EPA approval. There may be advantages to avoiding the delay associated with EPA processing of the implementation plan revision, particularly for additional TCMs which are already adopted or committed to by local agencies. However, more caution may be appropriate for revisions to emissions budgets and deletion or substitution of TCMs.

EPA is not proposing that other changes which could affect conformity determinations, such as the publication of new emissions models or the adoption of changes in planning assumptions, would necessarily trigger conformity determinations for the transportation plan. These changes would be incorporated as other triggers occur or at the time of the next periodic conformity determination, which will occur at intervals of no more than three years. Although ideally new conformity determinations would be made whenever new information becomes available, the stability of the transportation planning process requires that triggers for determinations be limited and predictable. Changes in emissions models or planning assumptions may occur too frequently to justify triggering a new determination.

B. Content of Transportation Plans

EPA is proposing requirements for how specifically projects must be defined in the transportation plan in order for their emissions to be estimated sufficiently for a conformity demonstration. EPA believes that transportation plans should be sufficiently specific to allow meaningful regional emissions estimates. However, the specificity necessary to quantify regional emissions depends on the sensitivity of an area's modeling capabilities. EPA is proposing two-tiered specificity requirements in order to accommodate the differing capabilities and resources of MPOs.

EPA is proposing the most specificity for plans in serious, severe, and extreme ozone areas and serious CO areas. After January 1, 1995, the proposed rule would require plans in these areas (hereinafter referred to as specific plans) to be specific enough to be analyzed using state-of-the-art travel demand network models. Because these areas have the worst air quality, they have the most need for accurate regional analyses.

In other areas, EPA would require that the transportation system envisioned for the future specifically enough to allow emissions from the plan to be quantified. Because they may not have network models, these areas would not require transportation plans which are as highly specific as those EPA is proposing for the serious and above areas. However, areas which have already been developing specific plans would be required to continue doing so.

EPA is proposing to allow areas which are "bumped up" to a serious classification two years to meet the more rigorous plan content requirements. This will allow these areas time to specify their networks and perform the other research and data collection activities necessary to develop network models and specific plans.

The proposed requirements would supplement other regulations governing the format or content of transportation plans. Furthermore, the degree of specificity required in the plan would not preclude the consideration of alternatives in the NEPA process or other project development studies. If the NEPA process were to result in a project with a design concept and scope significantly different from that in the plan or TIP, the project could still be found to conform under the proposed conformity criteria and procedures for projects which are not from a conforming plan and TIP.

C. Fiscal Constraints on Plans and TIPs

ISTEA requires that the transportation plan include a financial plan that demonstrates how the transportation plan can be implemented, indicates resources from public and private sources that are reasonably expected to be available throughout the plan's timeframe, and recommends any innovative financing. ISTEA also requires that prior to a project's inclusion in a TIP, full funding must be reasonably anticipated to be available within the time period contemplated for completion of the project. EPA anticipates that DOT will issue a rule or interpretation to more specifically implement these provisions.

EPA believes these ISTEA requirements will adequately ensure that the transportation activities analyzed for conformity can realistically be built, and therefore is proposing that plans and TIPs comply with the ISTEA requirements.

D. Summary of Proposed Criteria and Procedures

1. Pollutants and Types of Analyses

Because the definition of conformity in CAA section 176(c)(1)(B) refers to an activity's impact on the NAAQS, EPA would require conformity determinations to include analyses of local CO concentrations ("hot spots") in CO nonattainment and maintenance areas; analyses of PM_{10} hot spots in PM_{10} nonattainment and maintenance areas; regional analyses of CO in CO nonattainment and maintenance areas; regional analyses of ozone precursors (volatile organic compounds and nitrogen oxides) in ozone nonattainment and maintenance areas; regional analyses of nitrogen oxide (NO_x) in NO_2 nonattainment and maintenance areas; and regional analyses of PM_{10} and PM_{10} precursors such as VOC and NO_x if the applicable implementation plan identifies transportation-related precursor emissions within the area as a significant contributor to the PM_{10} nonattainment problem) in PM_{10} nonattainment and maintenance areas. Projects also would be required to be designed and funded to comply with PM_{10} control measures for control of fugitive dust from construction activities and any other transportation-related PM_{10} control measures in the applicable PM_{10} implementation plan. EPA would not require analyses of local ozone or NO_2 concentrations or precursor emissions because they are regional-scale pollutants.

Based on available emissions information, EPA believes highway and transit motor vehicles are not significant sources of lead or sulfur dioxide. Therefore, transportation plans, TIPs, and projects are presumed to conform to the applicable implementation plans for these pollutants.

If a fully approved implementation plan demonstrates that a constraint on regional PM_{10}, PM_{10} precursors, or CO emissions is not necessary to ensure attainment, those regional emissions tests would not apply for conformity. This would be the case if historical PM_{10} or CO violations were attributable to sources other than motor vehicles, or if CO violations can and will be solved by localized small-scale actions only.

2. Difference in Criteria and Procedures by Period of Time

The criteria and procedures for determining conformity would vary according to the period of time in which the determination is made. There are three periods of time outlined in this rule: the interim period (Phase I and Phase II), the control strategy period, and the maintenance period. A given area may be in different periods with respect to different pollutants.

Phase I of the interim period, which lasts until the effective date of the final rule, is governed directly by the provisions of the CAA. The EPA/DOT interim conformity guidance of June 7, 1991 is available as an informal joint interpretation of the statute with respect to those provisions. Phase II of the interim period would begin on the effective date of the final rule and would last until EPA approves or promulgates implementation plan revisions with reasonable further progress and attainment demonstrations. (Note: Phase II will terminate on different dates for different areas.) Approval of these

implementation plan revisions would begin the control strategy period, which would continue until the area is redesignated as an attainment area. After an area is redesignated to attainment, it would be considered in the maintenance period. Although the CAA requires no further planning actions or changes in control strategies after a certain number of years as a maintenance area (a maximum of twenty), there is no explicit end of the maintenance period.

The control strategy period and the maintenance period would have the same criteria and procedures for determining conformity. However, the interim period would have different criteria and procedures for regional analysis and project-level analysis from those that apply during the control strategy and maintenance periods.

EPA is proposing interim period criteria and procedures because the emissions budget test required in section 176(c)(2)(A) of the CAA cannot be applied until emissions budgets are established in the implementation plan. The CAA acknowledges the need for an interim period and establishes interim requirements in section 176(c)(3). Although the interim period discussed in the CAA lasts until the conformity plan revisions are approved, EPA is proposing that the interim requirements be extended until the control strategy plan revisions are approved, because it would be impossible to apply the emissions budget test prior to such approval. The interim criteria proposed today differ somewhat from those in the joint EPA/DOT June 7, 1991, guidance, particularly in the treatment of non-federal projects.

The statutory interim period criterion requiring regional analysis, which is in section 176(c)(3)(A)(iii) of the CAA, applies only to ozone and CO areas. EPA is now also proposing a requirement for regional analysis of PM_{10} and NO_x, with a somewhat different criterion, to ensure that there is no increase in the frequency or severity of existing violations and to ensure timely attainment of the standards for these pollutants during the interim period, as required by section 176(c)(1)(B).

3. Overview of Criteria by Type of Action

All actions. Conformity determinations for all actions would be required to use the most recent planning assumptions, as required by section 176(c)(1) of the CAA, and the most recent motor vehicle emission estimation model.

Plans and TIPs. Conformity demonstrations for plans and TIPs would be required to include regional emissions analyses or tests and demonstrate timely implementation of TCMs in applicable implementation plans. Regional analyses would be required for plans and TIPs because these documents address the areawide transportation system.

In the control strategy and maintenance periods, regional emissions from plans and TIPs would need to be consistent with the implementation plan's emissions budgets. This criterion is required by section 176(c)(2)(A) of the CAA. In the interim period, regional analysis would need to demonstrate that each plan and TIP contributes to reductions in emissions of volatile organic compounds (an ozone precursor) and CO. In PM_{10} and NO_2 nonattainment areas, regional analysis would also need to demonstrate that PM_{10} and NO_x emissions would not be increased from 1990 levels. Regional analysis in the interim period is required by sections 176(c)(1)(B) and 176(c)(3)(A)(iii) of the CAA.

Regional analysis requirements for TIPs would differ according to the specificity of the area's transportation plan. In some circumstances in areas with specific plans, the regional emissions criteria could be satisfied without a new regional emissions analysis, as described further below.

In all periods, plans and TIPs would be required to provide for the timely implementation of TCMs consistent with the schedules included in the air quality implementation plan. Provision for the implementation of TCMs in the implementation plan is required for plans and TIPs in the interim period by section 176(c)(3)(A)(ii) of the CAA, and for TIPs in all other periods by section 176(c)(2)(B). EPA is proposing that plans must also satisfy this requirement during the control strategy and maintenance periods in order to ensure conformity to the purpose of the implementation plan (see section 176(c)(1)(A)). During the control strategy period, requiring the plans to provide for the timely implementation of TCMs would also prevent delay in the timely attainment of any milestones, as required by section 176(c)(1)(B)(iii) of the CAA.

Projects which are from a conforming plan and conforming TIP. In areas with a specific plan, a regionally significant project would be considered to be "from a conforming plan" if the project were specifically identified in the currently conforming plan. A project which is not regionally significant in an area with a specific plan, and any type of project in an area without a specific plan, would be considered to come from a conforming plan if it were identified in the plan, or if it were consistent with the policies and purpose of the plan and would not interfere with other projects specifically included in the plan. The content requirements for transportation plans do not require these types of projects to be specifically identified in the transportation plan, although they may be.

A project of any type would be considered to be from a conforming TIP only if the project were specifically included in the currently conforming TIP, if the project's design concept and scope were adequate at the time of the TIP conformity determination to determine its contribution to the TIP's regional emissions, and if the project's design concept and scope had not changed significantly from those described in the TIP.

In areas other than CO and PM_{10} nonattainment and maintenance areas, projects would require no further analysis if it could be demonstrated that they were from a conforming plan and TIP. They would not require regional analysis because it would already have been performed for the conformity determinations on the plan and TIP. Section 176(c)(2)(C) of the CAA provides for this approach.

In CO and PM_{10} nonattainment and maintenance areas, conformity determinations for projects which are from a conforming plan and TIP would also need to be analyzed for their impacts on local CO and PM_{10} concentrations. During all periods, a finding would need to be made by the MPO and DOT that a project would not cause or contribute to any new localized CO or PM_{10} violation or worsen existing CO or PM_{10} violations, in order to satisfy the requirements of CAA section 176(c)(1)(B). During the interim period in CO nonattainment areas, projects would also need to eliminate or reduce the severity and number of localized CO violations. This is required in section 176(c)(3)(B)(ii) of the CAA.

All projects would have to be designed and funded to comply with PM_{10} control measures in the implementation plan, as required independently by the implementation plan.

Projects which are not from a conforming plan and conforming TIP. Projects which are not from a conforming plan and TIP would be those projects not identified in a conforming TIP, projects whose design concept and scope are significantly different than those described in the TIP

or were inadequate to determine emissions at the time of the TIP conformity determination, and in areas with specific plans, those regionally significant projects which are not specifically included in the plan.

Demonstrations of conformity for these projects would need to include regional analyses, analyses of local impacts in CO and PM_{10} nonattainment and maintenance areas, and an examination of the impacts on timely implementation of TCMs. These projects would be required to comply with PM_{10} control measures in the implementation plan, and there would need to be a conforming plan and TIP in place.

Case-by-case approval for projects which are not from a conforming plan and TIP is provided for in section 176(c)(2)(D) of the CAA. These projects would require a regional analysis which considers emissions from the project together with emissions from the plan and TIP. The analysis would have to demonstrate that if the project were added to the plan and TIP, the plan and TIP would still conform. This regional analysis could be performed at the time of the plan or TIP conformity demonstrations if so desired.

In CO and PM_{10} nonattainment and maintenance areas, the local impacts of all projects would need to be considered. Therefore, the proposed requirements for projects not from a conforming plan and TIP are the same as those discussed for projects which are from a conforming plan and TIP.

In any area, projects which are not from a conforming plan and TIP could not conform if they would interfere with the implementation of any TCM in the implementation plan.

E. Discussion of Criteria and Procedures

1. Latest Planning Assumptions

Conformity determinations for all actions would need to be based upon the estimates of current and future population, employment, travel, and congestion which have been most recently developed by the MPO or other agency authorized to make such estimates and approved by the MPO. In addition, the most recent road and bridge tolls, transit routes, fares, and other transit system operational policies would have to be considered in conformity determinations. Authorization to make estimates may be a matter of State law, and the implementation plan revision establishing conformity procedures should document the agency authorized to make the estimates.

Although revisions to planning assumptions would not trigger a conformity determination, the transportation and air quality modeling required for future conformity determinations would need to reflect the revised assumptions.

When a conformity determination is based on a previous analysis and no new transportation or air quality modeling is otherwise required (as may occur for TIPs which are from a specific plan), EPA would not require new modeling solely to incorporate revised assumptions.

2. Latest Emissions Model

EPA is proposing a grace period after the release of a new motor vehicle emissions model in order to allow planners time to install it and understand its changes. EPA and DOT would consult to determine the length of the grace period, which would be a minimum of three months and a maximum of two years. In this way, EPA and DOT could allow a longer grace period within the two-year limit when it might be necessary for States to revise their implementation plans to establish new emissions budgets consistent with the new models, or when transportation plans must be revised very substantially.

EPA believes that this grace period is consistent with the four-part test for grandfathering established in *Sierra Club* v. *EPA*, 719 F.2d 436 (D.C. Cir. 1983). These tests include whether the new rule represents an abrupt departure from previously established practice, the extent to which a party relied on the previous rule, the degree of burden which application of the new rule would impose on the party, and the statutory interest in applying the new rule immediately. In this case, use of a new emissions model is clearly an abrupt departure from use of the prior emissions model. Ongoing planning using the prior model would clearly have relied on the existence of and ability to use the old model. Furthermore, it would impose a significant burden on planners to stop in midstream and immediately redo ongoing planning using the new model. These factors taken together appear to outweigh any statutory interest in requiring use of the new emissions model effective immediately upon release.

EPA believes that the appropriate amount of time for planners to incorporate use of the new emissions model will vary according to the circumstances of the individual situation, and is thus providing for a variable grace period keyed to the needs of the situation. For instance, if the new model produces emissions estimates which are significantly higher than had been expected using the previous model, States may wish to revise their attainment demonstration to allow an increased motor vehicle emissions budget. EPA believes that while States are making this decision, consistency with the implementation plan's emissions budget should be demonstrated using the previous model, which was also used to develop the implementation plan. Such a grace period would last no more than two years and would allow States time to reconcile the emissions budget with the new model without disrupting ongoing transportation activities.

States may also wish to revise the implementation plan's motor vehicle emissions budget if the new model produces emissions estimates which are significantly lower than had been expected. In this case, the State may wish to allocate the budget windfall to stationary sources. A grace period would prevent new transportation activities from consuming the budget windfall before the State had made its allocation decisions.

3. Timely Implementation of TCMs

In order for a TCM to be considered to be implemented "consistent with schedules included in the applicable implementation plan," as required by section 176(c)(2)(B) of the CAA, the TCM would have to be planned and programmed consistently with both the definition and schedule included in the implementation plan. That is, the TCM's physical arrangement, legal provisions, pricing policies, and other action items would have to be consistent with those described for the TCM in the implementation plan. However, the TCM would not be required to demonstrate that it has achieved the predicted effect on emissions or personal behavior in order to be considered consistent with the implementation plan, unless the implementation plan explicitly provided such a requirement.

EPA believes that the requirement for timely implementation in section 176(c)(2)(B) applies only to those TCMs which are eligible for funding under title 23 U.S.C. or the Federal Transit Act. The plan and TIP must avoid interfering with non-federally funded TCMs, however, and in this sense provide for their implementation to the extent of the plan and TIP's authority.

TCMs which are being implemented consistent with the schedules in the implementation plan could be provided for in any manner, including funding solely by State, local, or private sources. If the TIP does not include projects

which are non-federally funded, the conformity determination can be made if there is material accompanying the TIP which provides documentation that those TCMs which are eligible but not proposed for Federal funding are being implemented consistent with the schedules in the implementation plan.

EPA considered several mechanisms by which a plan and TIP could provide for the expeditious implementation of TCMs which have been delayed and are therefore currently planned and programmed on a schedule which is not consistent with the schedule in the implementation plan. The central issues involve how much effort should be required to close the schedule gap, and how to prevent further delays from occurring.

One means of providing for the expeditious implementation of TCMs involves the use of Federal funds. For example, EPA considered requiring TCMs which are eligible for Federal funding and are behind the schedule in the implementation plan to receive maximum priority in Federal funding. However, DOT reports that a requirement for Federal funds to be set aside for TCMs is not statutorily permissible under title 23 U.S.C. and the Federal Transit Act. At the same time, EPA believes that simply requiring Federally fundable TCMs which are behind schedule to be included in the next plan and TIP would not be sufficient, because this approach would not address the sources of the delays in implementation.

Therefore, EPA is proposing that if TCMs which are in the implementation plan and eligible for Federal funding are behind schedule, the TIP may be found to conform only if past obstacles to implementation have been identified and are being overcome, and if State and local agencies with influence over approvals or funding are giving TCMs maximum priority. This approach accommodates unforeseen obstacles to implementation, but prevents a positive conformity determination until all possible actions to overcome the obstacles are being pursued.

In addition, if Federal funds have been programmed for a TCM but the funds have not been obligated and the TCM is behind schedule, this proposal would not allow those funds to be reallocated to any TIP projects which are not TCMs. If there were no other TCMs in the TIP, those funds could be reallocated to projects which are eligible for Federal funding under ISTEA's Congestion Mitigation and Air Quality Improvement Program (CMAQ). Under ISTEA, no CMAQ funds may be provided for a project which will result in the construction of new capacity available to single occupant vehicles, unless the project consists of a high occupancy vehicle facility available to single occupant vehicles only at other than peak travel times.

EPA believes it is unreasonable to find a plan or TIP in nonconformity (and therefore withhold Federal funds for all TIP projects) until TCM implementation is returned to its schedule. Such an approach does not allow for uncontrollable delays in TCM implementation. However, EPA requests comment on whether the rule should require that when a TCM falls behind the schedule in the implementation plan, the State must submit an implementation plan revision with a new schedule for implementation of the TCM and the required demonstration that adequate legal authority and resources exist to carry it out.

Although today's proposal would not prohibit a finding of conformity simply because a TCM is behind schedule, the regional emissions analysis would not be permitted to assume emissions reduction credit from a TCM which is behind schedule until its implementation is assured. This would prevent conformity findings from being based on unrealistic assumptions, and it would provide an incentive to implement the TCM which is behind schedule or some other TCM with similar emissions reduction potential.

EPA's proposal would not allow TCMs to be approved or funded in the absence of a conforming plan and TIP. The effects of TCMs must be analyzed in the context of the entire transportation system, because the effects of TCMs may depend on how they are incorporated in that overall scheme.

Definition of a TCM. As defined in this proposal, "transportation control measures" would include those transportation measures specifically identified and committed to in the applicable implementation plan. In order to ensure that all such TCMs can be clearly identified by all affected units of government and other interested parties, States are encouraged to specifically designate such measures as TCMs in their implementation plans.

In order to facilitate early agreement on the responsibilities of the transportation community, EPA would require the interagency consultation process to develop a list of TCMs in the implementation plan. EPA believes that TCMs need to be clearly and specifically defined in order for the transportation community to effectively provide for their timely implementation. Therefore, EPA believes TCMs in the implementation plan must be specific in terms of scale, location, and the process of implementation, enforcement, monitoring, and maintenance. The CAA requires States to hold public hearings before they may adopt an implementation plan. Because of the conformity implications associated with including TCMs in the implementation plan, EPA believes it is especially important for the public to be made aware of the TCMs in the implementation plan.

4. Projects From a Conforming Plan and Program

Section 176(c)(2)(C) of the CAA allows projects which come from a conforming plan and TIP to be found to conform without further regional analysis. Federal projects which are not demonstrated to come from a conforming plan and TIP would require regional analysis consistent with the requirements of section 176(c)(2)(D). EPA believes that the proposed interpretation of "from a conforming plan and TIP" would ensure that those projects which have already been considered in the plan and TIP's regional analysis would be exempted from further regional analysis.

5. Localized CO or PM_{10} Violations

EPA is proposing to require quantitative hot-spot analyses only when qualitative demonstrations cannot clearly demonstrate that the project would not cause or contribute to a new localized CO or PM_{10} violation or increase the frequency or severity of an existing violation. Not every project needs quantitative modeling to determine its impacts on localized concentrations, and allowing qualitative analyses in some circumstances would allow conservation of analysis resources. Because any possibility of a new or worsened violation would require a quantitative analysis, allowing the option for qualitative analysis would not diminish air quality protection.

A seemingly new violation could be considered to be a relocation and reduction of an existing violation only if it were in the area substantially affected by the project and if the predicted design value for the site would be less than the design value without the project—that is, if there would be a net air quality benefit. (The design value is the standardized representation of the current ambient pollution level.)

EPA firmly believes that some reasonable allowance of this sort is necessary to accommodate projects which may move a hot spot a short distance, but which improve air quality

overall. EPA is aware of concerns that this allowance may be vague due to the lack of definition of "area substantially affected by the project." If that area is too large, it would not be appropriate to consider a violation a relocation of an existing one. However, EPA believes that the size of the area cannot be established upfront for all situations, as it will depend heavily upon local circumstance and meteorology. Consequently, EPA believes that this must be determined on a case-by-case basis in the context of the conformity determination. EPA requests comment on other approaches or definitions which also provide a reasonable interpretation of "new" violations.

This criterion could be satisfied for a project from a conforming transportation plan or TIP regardless of any impact which the project may have on actual or potential regional-scale emissions, provided all other applicable criteria are satisfied.

EPA and DOT plan to develop guidance on methods for modeling PM_{10} hot spots.

Construction-related activities. EPA believes that conformity should address long-term emissions from the transportation system, and that conformity should not prevent project implementation because of temporary emissions increases. In addition, the NEPA process provides the most appropriate forum to analyze construction-related emissions impacts and to establish mitigation measures.

Analyses and findings regarding localized CO and PM_{10} concentration impacts would not have to include construction-related activities which cause temporary and self-correcting increases in local concentrations. Temporary and self-correcting increases are defined as those which occur only during the construction phase and last five years or less at any individual site. Each site which is affected by construction-related activities would be considered separately, using established "Guideline" methods.

Although construction-related fugitive dust contributes to PM_{10} nonattainment in many areas, the extent of the problem is not well known. Nonattainment areas differ greatly in their potential for hot spots, and within an area there may be variations according to the season and the site. Areas with dust problems have been crafting strategies to demonstrate attainment utilizing available emissions estimation techniques and modeling, but there are continuing efforts to better quantify construction dust emissions and control measure effectiveness. EPA requests comment on what evidence must be developed and considered when determining that no new violations will be caused or existing violations worsened. The interagency consultation process would have to address what procedures are appropriate.

PM_{10} hot spots from bus terminals and transfer points. Although EPA expects that typically-sized diesel bus terminals and transfer points will not cause or contribute to new PM_{10} violations, EPA believes it is practical to require a determination to that effect. EPA requests comment on allowing DOT to make a categorical determination based on appropriate modeling of various terminal sizes and configurations if it believes this would make the planning process more certain and efficient. The modeled scenarios used to make the categorical determinations would need to be derived in consultation with EPA, and more refined analysis would be necessary for projects which do not meet the parameters of the modeled scenario.

Other PM_{10} hot spots. Generally, EPA believes that direct vehicle PM_{10} emissions are capable of causing violations only in situations of unusually heavy diesel truck/bus traffic and limited dispersion, such as street canyons. FHWA and FTA projects may affect the density of diesel vehicle traffic on such streets. EPA requests comment on requiring quantitative analyses in order to satisfy this hot-spot criterion only for sites at which violations have been verified by monitoring and others which have essentially identical dispersion conditions and diesel vehicle traffic (including sites near one at which a violation has been monitored).

Increased diesel transit bus service at sites with known violations may be a concern. However, the only relevant Federally-supported activity which is subject to conformity is the purchase of new buses for a major expansion of the fleet. EPA believes that new bus purchases are not causally related to the worsening of PM_{10} hot spots. EPA therefore proposes that conformity determinations for new bus purchases would not be required to address localized PM_{10} violations. In addition, because of the more stringent PM_{10} standard now in effect for urban buses, which is being phased in from 1991 to 1994, all current and future bus purchases will put significantly cleaner vehicles on city streets.

6. Consistency With Emissions Budgets

Emissions budgets. The implementation plan's demonstration of reasonable further progress and attainment will be based on certain projected motor vehicle emission levels for future years. These motor vehicle emissions will be the emissions budget for later conformity determinations. Thus, the budget will be defined for a number of future dates, depending on the reasonable further progress and attainment showings required for the area.

States will need to make sure that the motor vehicle emissions budget is stated clearly and unambiguously in the implementation plan to facilitate future conformity determinations. EPA would allow an area to have a single areawide budget for each criteria pollutant or precursor for which it is in nonattainment. However, because photochemical grid models estimate vehicle emissions for many small grid squares, States would also have the option to specify subregional emissions budgets. Thus, the implementation plan could either establish a budget using the sum of vehicle emissions from all grids in the area, or it could divide the area into major subareas and establish a budget for each. Subregional budgets would provide additional assurance that through future conformity determinations transportation plans and programs will produce emission patterns that will achieve attainment.

In some nonattainment areas the implementation plan's attainment demonstration may show that motor vehicle emissions are not an important part of the nonattainment problem. This is most likely with PM_{10} violations near industrial sources. In such a situation, the implementation plan may establish no budget for motor vehicles and explicitly provide that no regional emissions tests are needed for conformity determinations. EPA will closely scrutinize such claims before approving the implementation plan.

Need for analysis of long-term regional emissions. Because emissions budgets will address a timeframe which is longer than any single TIP, demonstration of the TIP's consistency with the implementation plan's budget should be done in the context of the long-term transportation system. Therefore, EPA's proposal would require regional analyses of TIPs to include all expected regionally significant projects in the timeframe of the plan, regardless of their funding source.

In some areas, plans will describe future actions specifically enough to allow comprehensive regional analysis with network models. In these areas, as described below, EPA would require the TIP's conformity determination to use the plan's regional analysis. In areas without specific plans, the plan's

regional analysis will most likely rely on demographically-based projections and adjustments to current VMT and emissions (based on planned TCMs and any regionally significant projects that are identified). These regional analyses would not define projects and estimate emissions with sufficient detail to ensure that any TIP derived from the plan is consistent with the emissions budget. In addition, there would be much flexibility to place newly conceived projects in the TIP which were not identified in the plan. Therefore, EPA would also require a regional analysis of the TIP in areas without specific plans.

TIPs from specific plans. Under this proposal, a TIP which is from a specific plan could demonstrate consistency with the emissions budget without additional regional analysis. EPA believes that if the TIP is financially feasible and consistent with the plan, it is appropriate to rely on the regional analysis which has been performed for the plan.

For the TIP to be considered financially feasible, the TIP would have to be consistent with the Federal funding which may be reasonably expected for the timeframe of the TIP. Necessary State/local matching funds would also have to be consistent with the revenue sources expected over the same period.

For the TIP to be considered consistent with the plan, the following conditions would have to be satisfied: (1) The TIP would have to contain all regionally significant projects which must be started in the TIP's timeframe in order to achieve the highway and transit system envisioned by the plan in its horizon years; (2) all TIP projects which add or modify regionally significant highway or transit facilities would have to be part of the specific highway or transit system envisioned in the plan's horizon years; and (3) there could be no regionally significant TIP projects which have a design concept or scope different from those in the plan.

The tests for financial feasibility and consistency with the plan would help ensure that the projects assumed in the plan will be built, and that the TIP includes no projects different from those assumed in the plan's analysis.

If the TIP is not financially feasible, EPA would require the TIP to be amended until feasibility can be demonstrated.

If the TIP's consistency with the plan cannot be demonstrated, EPA is proposing that either the TIP or the plan must be amended. Thus, if the TIP includes projects which are not from the plan or if the TIP does not include projects necessary for the plan's envisioned network, either the plan would need to be amended and reanalyzed for conformity, or the TIP would need to be amended to be consistent with the current plan. If the plan is amended to be consistent with the proposed TIP, and the plan is found to conform after a new regional analysis, no further analysis of the TIP would be required.

EPA would require the plan and/or TIP to be amended to be consistent before a conformity determination can be made for the TIP so that the plan's regional analysis can be the basis for TIP and project conformity determinations in the future. Because the conformity of each future TIP will depend on its relationship to the plan, additions or deletions to the envisioned transportation network must be reflected in the plan.

EPA requests comment on whether there should be a distinction in the regional emissions analysis requirements between specific plans and non-specific plans, because metropolitan planning under ISTEA will require future transportation plans to define project design concept and scope sufficient to determine conformity.

Projects not from a conforming plan and conforming TIP. In areas without specific plans, EPA would require all projects not from a conforming plan and TIP to be regionally analyzed. The regional analysis would have to estimate the emissions expected from the transportation network if the proposed project, the currently conforming plan and TIP, and all other regionally significant projects expected in the nonattainment or maintenance area are implemented. The analysis would also have to account for the emissions of previously approved projects which were not from a plan and TIP. This approach is consistent with section 176(c)(2)(D) of the CAA.

In areas with specific plans, EPA is proposing that projects could be found to conform without additional regional analysis if they are consistent with the plan, even if they are not specifically included in the latest conforming TIP. A demonstration of consistency would require that regionally significant projects are part of the specific system envisioned in the plan's horizon years which has been analyzed for emissions, even though the projects are not formally included in both the plan and TIP. A demonstration of consistency with the plan would also have to show that allocating funds to the project would not delay the implementation of those projects in the transportation plan or TIP which are necessary to achieve the highway and transit system envisioned by the plan.

If a project is not consistent with a specific plan, EPA would require additional regional analysis as described for projects which are not from a conforming plan and TIP in areas without specific plans.

EPA anticipates that projects not from a conforming plan and TIP will be either newly conceived projects not expected when the TIP was prepared, or projects which are in the nonattainment or maintenance area but outside the metropolitan planning area. When the projects which are not from a plan and TIP are known at the time of the plan and TIP conformity determination, as in the latter case, only one regional analysis may be necessary. In that case, the plan or TIP's regional analysis would include those projects which are not from a TIP, and the analysis would have to demonstrate that the plan or TIP together with the extra projects is consistent with the emissions budget.

Special provisions for areas not required to demonstrate reasonable further progress and attainment. Nonattainment areas which are not required to demonstrate reasonable further progress and attainment may not have an emissions budget. Therefore, EPA is proposing special provisions for rural ozone nonattainment areas, marginal ozone areas, submarginal ozone areas, transitional ozone areas, incomplete data ozone areas, moderate CO areas with a design value of 12.7 ppm or less, and not classified CO areas. In addition, maintenance areas may not have a motor vehicle emissions budget in the applicable maintenance plan if that plan was approved under the provisions of the 1977 CAA, rather than the new provisions of the 1990 CAA.

During the control strategy and maintenance periods, these areas would continue under the interim requirement to contribute to emissions reductions, unless they choose to submit an implementation plan revision with an attainment demonstration and emissions budget. If an area establishes an emissions budget, it would have to demonstrate that plans, TIPS, and projects not from a plan and TIP are consistent with the emissions budget.

The interim requirement to contribute to emissions reductions may be stricter than an emissions budget test. For example, an attainment demonstration may show that an area could have some emissions increases and still meet its attainment deadline.

7. Eliminate or Reduce the Severity and Number of Localized CO Violations

During the interim period, all projects in CO nonattainment areas would have to demonstrate that they would eliminate or reduce the severity and number of localized CO violations in the area substantially affected by the project. The number of violations resulting from the project's implementation would have to be less than the number of violations predicted without the project. The predicted design value for the site after the project's implementation would have to be less than the design value without the project.

As described above, EPA is proposing to require quantitative hot-spot analyses only when qualitative demonstrations cannot clearly indicate that the project would eliminate or reduce the severity and number of localized CO violations.

This interim requirement for CO nonattainment areas is established in section 176(c)(3)(B)(ii) of the CAA. EPA is proposing this requirement only in the context of localized CO violations, because regional violations are addressed by the requirement to contribute to reductions in CO emissions, as discussed below. This criterion could be satisfied for a project from a conforming transportation plan or TIP regardless of any impact which the project may have on actual or potential regional-scale emissions, provided all other applicable criteria were satisfied.

8. Contribute to Emission Reductions in Ozone and CO Areas

Overview. EPA is proposing that during the interim period, plans, TIPs, and projects not from a conforming plan and TIP would have to contribute to reductions in ozone precursor emissions (VOC) in ozone nonattainment areas and in CO emissions in CO nonattainment areas. A regional analysis would have to demonstrate that emissions from the transportation system if the proposed action(s) were implemented would be less than the emissions from the transportation system without the proposed action(s).

The regional analysis would establish a "Baseline" and "Action" scenario and analyze emissions from each scenario for certain future years. The analysis years would depend on the action being proposed, but would always include the attainment year. For each analysis year, the emissions predicted from the "Action" scenario would have to be less than those predicted from the "Baseline" scenario.

Although EPA is not proposing to require NO_x reductions in ozone areas during the interim period, States may require such reductions in their implementation plan revisions which establish the criteria and procedures for determining conformity.

Rationale. Section 176(c) (3) (A)(iii) of the CAA establishes the interim requirement for regional analysis in ozone and CO areas, which will eventually be replaced by a requirement for emissions budget tests during the control strategy and maintenance periods. The CAA requires plans and TIPs to "contribute to annual emissions reductions consistent with sections 182(b)(1) and 187 (a)(7)," which require reasonable further progress and attainment demonstrations.

However, the implementation plan revisions including these demonstrations will not exist during the interim period. Thus, the exact percentage reduction required from mobile sources will not be known. Therefore, reductions consistent with the reasonable further progress and attainment demonstrations could mean either the entire fifteen percent reduction by 1996 required for moderate and above ozone nonattainment areas for reasonable further progress, and arbitrary annual percentage reduction, or any nonzero reduction.

EPA does not believe that Congress intended the entire fifteen percent emission reduction to be achieved in motor vehicle emissions. Such an extreme measure would have been clearly stated. Sections 182(b)(1) and 187(a)(7) refer only to reasonable further progress, not the fifteen percent requirement; there is not a fixed percentage required for CO areas to demonstrate reasonable further progress.

In addition, EPA does not believe it is appropriate to require specific annual emissions reductions before they have been established in the reasonable further progress and attainment demonstrations. EPA believes the States should be allowed to decide how much reduction to require from motor vehicles and how much to require from stationary sources. Furthermore, until the implementation plan's emissions inventories are submitted, it will not be possible to determine the baseline from which emissions must be reduced. Therefore, EPA is interpreting the CAA's interim requirement to mean that plans, TIPs, and projects not from a conforming plan and TIP must contribute to emission reductions by any amount.

EPA believes that this interpretation is consistent with the statutory requirement. Section 176(c)(3)(A)(iii) requires contributions to annual emissions reductions consistent with sections 182(b)(1) and 187(a)(7). Section 187(a)(7) does not require any specific numerical amount of emission reduction, merely requiring such annual emission reduction as is necessary to demonstrate attainment. Section 182(b)(1) actually imposes two separate requirements. It first requires VOC reductions of 15% over six years, and then in a separate sentence requires such annual reductions as necessary to provide for attainment. EPA believes that the proper interpretation of § 176(c)(3)(A)(iii) is that by its own terms it refers only to the annual emission reductions in the second sentence of § 182(b)(1). Thus, areas are not constrained by any predefined percentage reduction for purposes of demonstrating conformity. Areas must simply demonstrate that activities contribute to annual emission reductions, which they may do by simply producing some positive emission reductions.

There is some reference in the legislative history that appears to indicate that Congress intended to impose a 15% reduction requirement on conformity demonstrations (136 Congressional Record, S16972, October 27, 1990). However, this legislative language simply misinterprets the clear reference in the statutory language to the annual emission reduction requirements in sections 182(b)(1) and 187(a)(7), rather than the 15% over six years requirement in section 182(b)(1). EPA agrees with the legislators that mobile source emissions should not be allowed to increase during the development of implementation plan emission budgets, but EPA believes that this requirement is met by showing some positive emission reduction.

A concern has been expressed that there may be long delays in establishing emission reduction targets for conformity purposes. These delays could occur because of delays in submitting emission budgets, because of the time which can elapse between adoption of budgets and formal revision of the implementation plan by EPA, or for other reasons. Because emission reduction targets are a key aspect of the conformity requirements, EPA is requesting comment on ways to alleviate the potential problems associated with delays. One specific suggestion which has been offered would place a cap on CO and ozone precursors during the interim period which is equal to the 1990 base year inventory of these pollutants, and no credit would be given for reductions in emissions from tailpipe standards. EPA notes that in the General Preamble for the Implementation of title 1 of the

Clean Air Act Amendments of 1990 (57 FR 13498, April 16, 1992), EPA rejected such an approach in the context of CAA section 182(d)(1)(A), which requires TCMs to offset growth in emissions from growth in VMT in severe and extreme ozone nonattainment areas and serious CO nonattainment areas. EPA believes this approach would have drastic implications. Since VMT is growing at rates as high as four percent per year in some cities, draconian measures such as mandatory no-drive restrictions would be necessary to achieve reductions from 1990 emission levels without credit for tailpipe standards. However, EPA is interested in other more workable approaches to handle the potential problems with delayed emissions budgets.

"Baseline" and "Action" scenarios. The regional emissions analysis would have to demonstrate that the emissions from the transportation system in the milestone and attainment years, if it included the proposed action and all other expected regionally significant projects (the "Action" scenario), would be less than the emissions from the current transportation system in the milestone and attainment years (the "Baseline" scenario). This "Baseline"/"Action" comparison would be required only during the interim period, except in areas which are not required to demonstrate reasonable further progress and attainment, as described above.

The "Baseline" scenario would include all in-place regionally significant highway and transit facilities, services, and activities; all ongoing travel demand management or transportation system management activities; and completion of all regionally significant projects in the nonattainment area that are currently under construction, undergoing right-of-way acquisition, come from the first three years of a previously conforming plan and/or TIP, or have completed the NEPA process (regardless of funding source).

If no major steps to advance a project have occurred within three years after completion of the NEPA process, 23 CFR 771.129 requires a written re-evaluation of the final NEPA document. If the written reevaluation requires a new NEPA document for design concept and scope or air quality reasons, a new conformity determination would be required for the project. This would deter an area from artificially inflating the "Baseline" scenario by including projects which are not actually being built.

The "Action" scenario is the future transportation situation that will result from the implementation of the action (i.e., plan, TIP, or project not from a plan and TIP) and other planned highway and transit projects, regardless of funding source. This would include all facilities, services, and activities in the "Baseline" scenario (unless the "Action" scenario specifies the deletion of some "Baseline" facilities, services, or activities); the completion of all TCMs and regionally significant facilities, services, and activities associated with the proposed action which will be operational by the analysis year; and the completion of expected regionally significant non-FHWA/FTA highway and transit projects that have clear funding sources and commitments leading to their implementation and completion by the analysis year. Although these non-FHWA/FTA projects may not be included in the plan or TIP, the "Action" scenario must account for all regionally significant projects in the aggregate in order to give a realistic approximation of the regional emissions burden.

Because the "Action" scenario would include non-FHWA/FTA projects, EPA would also allow the "Action" scenario to include non-FHWA/FTA TCMs which have been fully adopted and/or funded since the last conformity determination on the action. The "Action" scenario could also include the incremental effects of any non-FHWA/FTA TCMs which have been modified since the last conformity determination on the action to be more stringent or effective. These TCMs would not have to be identified in the implementation plan, but they would have to be fully adopted and/or funded in order to receive emissions reduction credit.

9. No Increase in Emission in PM_{10} and NO_2 Areas

EPA is proposing that emissions in PM_{10} and NO_2 nonattainment areas could not increase above 1990 levels during the interim period. EPA is proposing this requirement, rather than the "Baseline"/"Action" comparison proposed for ozone and CO areas, because the CAA does not include specific interim requirements for contributions to regional emission reductions in PM_{10} and NO_2 nonattainment areas. Furthermore, EPA believes that requiring a build/no-build comparison in PM_{10} and NO_x areas could have undesirable consequences which were unanticipated by Congress. A ceiling on NO_x and PM_{10} emissions at their 1990 level is proposed because the definition of conformity prohibits any increase in the frequency or severity of existing violations.

EPA believes it is reasonable to assume that when Congress was addressing ozone and CO, it established a build/no-build test under the then-accepted belief that a well-designed "build" scenario could reduce emissions without reducing VMT itself. In fact, the available emissions models of that time indicated that congestion relief measures can reduce ozone and CO emissions in any area by improving speeds. EPA notes that Congress reserved its VMT-oriented TCM requirements for only the areas with the very worst air quality. (See, for example, sections 182(d)(1)(A) and 187(b)(2).) This indicates that Congress expected most areas affected by conformity to have some tolerance for VMT growth.

There is no indication that Congress was aware that in many cases, NO_x emissions and PM_{10} emissions (depending on roadway type and classification and surface particulate loadings) increase with improved traffic flow and increased speeds. Also, there is no indication that Congress considered the potential for increased PM_{10} emissions from increased use of diesel transit buses. Both of these effects may make it difficult for a "build" scenario to demonstrate emissions reductions, other than by reducing VMT itself below what would otherwise occur. EPA does not believe Congress intended difficult VMT reductions in the interim period. Because EPA is not certain what degree of VMT reduction might be needed to pass a build/no-build comparison, and because the CAA Amendments do not appear to require it, EPA is not proposing a build/no-build comparison during the interim period in PM_{10} and NO_x nonattainment areas.

Instead, EPA believes that preventing emissions from increasing above 1990 levels would be sufficient to prevent the exacerbation of existing violations during the interim period. This will allow speed increases and associated increases in emissions, if these are offset by fleet turnover and other elements of the plan or program, such as paving or cleaning roads. Because PM_{10} and NO_x modeling for plans and TIPs is less common than VOC and CO modeling, EPA is not certain of the emissions impact and compliance difficulty of this approach as compared to a build/no-build approach. EPA therefore invites comment on whether the proposed approach is appropriate and feasible.

EPA believes 1990 is the most reasonable year to use as a baseline because it is the year the CAA amendments were enacted. Although there has been some decrease in NO_x emissions due to fleet turnover since

1990, this decrease is less than that in CO and VOC emissions. Therefore, there is a more limited opportunity for transportation actions to claim NO_x reductions from fleet turnover since 1990 in order to allow increased NO_x emissions from future development activities.

However, EPA notes that there is no requirement for a 1990 inventory in PM_{10} and NO_2 nonattainment areas. EPA invites comment on allowing other years to be used as the baseline, such as the year(s) of the ambient data upon which the designation was based (or, for PM_{10} nonattainment areas, upon which the moderate or serious classification was based).

F. Procedures for Estimating Emissions and Ambient Concentrations

1. Regional Emissions Analysis

Serious CO and serious, severe, and extreme ozone areas. After January 1, 1995, this proposal would require these areas to use network-based transportation demand models or models relating travel demand and transportation system performance to land-use patterns, population demographics, employment, transportation infrastructure, and transportation policies. The proposal includes detailed procedural requirements, and additional useful guidance on modeling practices may be found in EPA's section 187 VMT Forecasting and Tracking Guidance (March 1992) and the forthcoming National Association of Regional Councils' "Manual of MPO Modeling Practice."

Areas which are not serious CO or serious, severe, or extreme ozone. Unless these areas have been using network models, these areas could estimate regional emissions using methods which do not explicitly or comprehensively account for the influence of land use and transportation infrastructure on vehicle miles traveled (VMT) and traffic speeds and congestion. Such methods could extrapolate historical VMT or project future VMT by considering growth in population and historical growth trends for VMT per person. These methods would also adjust this extrapolated VMT in consideration of future economic activity, transit alternatives and other TCMs, specific major highway changes, and transportation system policies which make the demographically-based extrapolation alone inappropriate. Population growth has the largest influence on regional motor vehicle emissions and should be a sufficient predictor.

Rationale. EPA believes the proposed network modeling procedures reflect the current consensus in the transportation and air quality planning professions on minimum acceptable modeling practices. EPA welcomes comments on the proposed procedures and is monitoring developments from the National Association of Regional Councils' MPO Modeling Practices project.

EPA is reserving the most rigorous requirements for those areas which have the most extensive air quality planning needs and which are already encouraged to develop network models by other sections of the CAA. EPA is not proposing to require network models in all areas because it would be impractical for these areas to obtain the necessary financial and technical resources before their attainment date, which is 1996 at the latest. Areas which are currently using network models would be required to continue using them for conformity analyses. In addition, the new planning requirements associated with ISTEA are expected to encourage more areas to develop network models.

EPA requests comment on whether serious PM_{10} nonattainment areas should be required to use network models and develop specific transportation plans. Specifically, EPA requests comment on whether the air quality benefits from using network models to perform conformity analyses justify the financial investment which would be required.

Transportation control measures. Areas will need to project the effect of TCMs as part of performing the regional emissions analysis. The changes in travel time of day, mode choice, trip length, trip frequency, and travel speed will result in creditable emissions reductions. For the purposes of plan and TIP conformity, areas must assume a prospective level of TCM effectiveness which is consistent with the implementation plan. Those TCMs which are in place must be modeled consistent with the available information on the degree of compliance with the measures.

Construction-related activities. EPA believes that temporary emissions increases of VOC and CO due to construction-related traffic congestion will not cause violations at the regional level. These emissions changes are small increases due to traffic speed changes and are not associated with VMT growth, which is the primary concern with regional violations. Also, the NEPA process considers the construction-related impacts of projects and is intended to ensure that appropriate mitigation measures are considered. Therefore, EPA believes that emissions increases from construction-related congestion are not significant at the regional level, and such increases will not cause any new regional-scale violations or exacerbate existing ones.

However, construction activity can be a significant direct source of fugitive PM_{10} due to the disturbance of ground cover and the movement of construction vehicles on unpaved areas. In addition, construction vehicles can carry soil onto paved roads, where it can be re-entrained into ambient air by other passing vehicles.

EPA is proposing to require regional PM_{10} emissions analyses to consider construction-related fugitive PM_{10} in those areas with implementation plans which identify it as a contributor to the nonattainment problem. The regional analysis would have to account for the level of construction activity, the fugitive PM_{10} control measures in the implementation plan, and the dust-producing capacity of the proposed activities. Those areas with implementation plans which do not identify construction-related fugitive PM_{10} as a contributor to the nonattainment problem do not have to consider it in their regional emissions analysis.

2. Hot-spot Analysis

If consideration of local factors clearly demonstrates that the hot-spot criteria are satisfied, EPA would not require quantitative modeling. EPA believes that quantitative modeling is not necessary to demonstrate satisfaction of the hot-spot criteria in every case, since the range of FHWA and FTA projects includes many which could not reasonably be argued to have any significant CO emissions effect. However, at this time EPA cannot propose cutoffs on project size, geography, or other characteristics above which modeling is always required. Therefore, EPA requests comment on whether and how to more clearly define when quantitative modeling is and is not required. EPA also invites comment on specific procedures or evidence which should be considered for qualitative hot-spot analysis.

CO hot-spot modeling. EPA is proposing that when quantitative modeling is required, the choice of a hot-spot model and associated methods and assumptions must be the subject of interagency consultation. However, EPA would require quantitative CO hot-spot analyses to be based on the applicable air quality models, data bases, and other requirements specified in the most recent version of the "Guideline on Air

Quality Models (Revised)" (EPA publication no. 450/2–78–027R), including all Supplements finally published in the **Federal Register** by the date of this final rule, in those locations, areas, or categories of sites which the implementation plan identifies as sites of current violation or possible current violation, and at other sites if the use of the "Guideline" models is practicable and reasonable given the potential for violations. The "Guideline on Air Quality Models" is used in the implementation plan's attainment demonstration, and EPA believes it is advisable to use consistent modeling techniques at sites which are the same as or similar to those sites addressed in the attainment demonstration. Other quantitative models could be used at such sites only if after the interagency consultation process and with the approval of the EPA Regional Administrator, it is determined that "Guideline" models are not practicable or not reasonable.

At sites which are not identified as violations and at which the use of "Guideline" models is not practicable or reasonable, EPA would allow other quantitative methods to be used if they represent reasonable and common professional practice. Where "Guideline" and non-"Guideline" models are both available, "Guideline" models would have to be given the greatest consideration. EPA is proposing this flexibility because it is not clear that sites which are not identified as current violations or possible current violations need the same modeling techniques as those used in the implementation plan.

G. Exempt Projects

EPA is proposing that certain highway and transit projects would not require a conformity determination and could proceed toward implementation even without a conforming transportation plan and TIP because of the nature of such projects and their inherent lack of impact on air emissions. Alabama Power v. EPA, 636 F.2d 323, 360, D.C. Cir. 1979, gives EPA the authority to create such de minimis exemptions. Examples of such projects include various safety projects; certain mass transit projects, such as rehabilitation of transit vehicles and construction of small passenger shelters; continuation of ride-sharing and vanpooling promotional activities; bicycle and pedestrian facilities; landscaping; and sign removal. Any specific project in these categories may be made non-exempt if the MPO and other agencies in the interagency consultation process concur that it has potentially adverse emissions impacts.

By exempting these projects with neutral air quality impacts, EPA would minimize the resource use and project delays which could be associated with the conformity process. EPA also believes that areas without a currently conforming plan and TIP should be permitted to implement projects with neutral air quality impact. Although no conformity determination would be required of exempt projects, States and MPOs should ensure that exempt projects would not interfere with TCM implementation. If TCM implementation is delayed because of exempt projects, future TIPs and plans may not be able to receive a conformity finding.

EPA also proposes that certain projects be exempt from regional emissions analyses. These projects, which EPA believes have no regional emissions impacts, would include intersection channelization and signalization projects; interchange reconfiguration projects; changes in vertical and horizontal alignment; truck size and weight inspection stations; and bus transfer terminals.

These projects would require analysis of local impacts for project-level conformity determinations, but could be excluded from regional analyses of plans, TIPs, and projects which are not from a conforming plan and TIP. EPA believes that exempting these projects from regional analyses would simplify regional analysis and minimize the burden of conformity. Because these projects have no impact on regional emissions, they cannot cause an emissions budget to be exceeded, and they therefore satisfy the requirements of CAA section 176(c)(2)(D). Therefore, these projects could proceed even in the absence of a conforming plan and TIP.

However, this provision would not waive any planning requirements established by ISTEA.

VIII. Environmental and Health Benefits

This rule will help ensure that the implementation plan achieves its goal of attaining air quality standards. The environmental and health benefits of attaining the national ambient air quality standards are attributable to the strategies contained in the implementation plan rather than to this rule directly.

IX. Economic Impact

The primary impact of this rule involves the increased requirements for MPOs to perform regional transportation and emissions modeling and document the regional air quality impacts of transportation plans and programs. Because conformity requirements have existed in some form since 1977, the framework for consultation and TCM tracking has already been established.

The impact of today's proposed conformity requirements on MPOs may vary widely depending on the pollutant for which an area is in nonattainment, the classification of the nonattainment area, the population of the area, and the technical capabilities already developed in the area.

The approximately 25 MPOs which will be subject to the most stringent modeling requirements—which are also among the largest MPOs—have been spending during Phase I of the interim period approximately $150,000 for a conformity determination on the transportation plan and TIP. Costs for smaller MPOs in nonattainment areas which are not classified as serious or above have ranged from $10,000 to $60,000.

These estimates do not necessarily reflect the costs which will result from today's proposed rule. On one hand, these may be overestimates of the costs, because determinations will probably become less expensive as the MPOs gain experience. For example, for future determinations it may be possible to perform the modeling with fewer runs. On the other hand, these estimates do not reflect the more specific requirements of today's rule and may therefore underestimate the cost of determinations in the control strategy period. EPA is continuing to research the costs of conformity to MPOs.

Estimates of conformity costs among the larger MPOs vary from as low as $50,000 to as high as $725,000 (for a TIP, a plan, and TIP amendments associated with the plan), which illustrates the difficulty of estimating the costs specifically associated with conformity's increased requirements. Because ISTEA and other CAA provisions also indirectly require increased modeling, it is difficult to separate the costs attributable to the conformity requirements. For example, ISTEA assigns more responsibility to the MPOs and shifts the planning focus to intermodalism and congestion management. This will require more sophisticated transportation modeling. The VMT tracking and forecasting requirements in sections 182 and 187 of the CAA will also promote the use of transportation demand network models in some nonattainment areas.

In addition, although the conformity requirements may prompt additional data collection and model development, these costs cannot be solely attributed to

conformity. It is an ongoing responsibility of MPOs to review and upgrade their analysis capabilities to reflect the most recent understanding of travel demand and transportation forecasting. Resource constraints during the 1980's prevented many MPOs from updating their analysis procedures, so conformity is in many cases simply raising the priority of modeling improvements.

Metropolitan planning is eligible for funds under ISTEA. In addition, EPA has attempted to minimize the costs of conformity in several ways. First, EPA is proposing flexible methodological requirements for regional analyses in areas which don't use network models, in order to accommodate the varying technical capabilities of MPOs. In addition, by designating projects which are exempt from conformity determinations or regional analyses, EPA is allowing project sponsors to conserve their analysis resources. Finally, EPA has attempted to minimize the frequency of conformity redeterminations by limiting the number of triggers and by allowing grace periods before the use of new emissions models and following an area's reclassification.

X. Public Participation

A. Comments and the Public Docket

EPA and DOT welcome comments on all aspects of this proposed rulemaking. All comments should be directed to the EPA Air Docket Section, Docket No. A–92–21 (see "ADDRESSES"). As noted above in section II. D., EPA is currently drafting an NPRM proposing criteria and procedures for determining conformity of general Federal actions (general conformity rule). If EPA determines it is appropriate, EPA may reopen the public comment period on this rule to coincide with the public comment period on the general conformity rule.

B. Public Hearing

Anyone who wants to present testimony about this proposal at the public hearing (see "DATES") should, if possible, notify the contact person (see "FOR FURTHER INFORMATION CONTACT") at least seven days prior to the day of the hearing. The contact person should be given an estimate of the time required for the presentation of testimony and notification of any need for audio/visual equipment. A sign-up sheet will be available at the registration table the morning of the hearing for scheduling those who have not notified the contact earlier. This testimony will be scheduled on a first-come, first-serve basis to follow the previously scheduled testimony.

EPA requests that approximately 50 copies of the statement or material to be presented be brought to the hearing for distribution to the audience. In addition, EPA would find it helpful to receive an advance copy of any statement or material to be presented at the hearing at least one week before the scheduled hearing date. This is to give EPA staff adequate time to review such material before the hearing. Such advance copies should be submitted to the contact person listed.

The official records of the hearing will be kept open until the close of the comment period to allow submission of rebuttal and supplementary testimony. All such submittals should be directed to the Air Docket, Docket No. A–92–21 (see "ADDRESSES").

Dick Wilson is hereby designated Presiding Officer of the hearing. The hearing will be conducted informally, and technical rules of evidence will not apply. A written transcript of the hearing will be placed in the above docket for review. Anyone desiring to purchase a copy of the transcript should make individual arrangements with the court reporter recording the proceeding.

As noted above in section II. D., EPA is currently drafting an NPRM proposing criteria and procedures for determining conformity of general Federal actions (general conformity rule). If EPA determines it is appropriate, EPA may hold additional public hearings concurrently or consecutively with the public hearings on the general conformity rule.

XI. Administrative Requirements

A. Administrative Designation

Under Executive Order 12291, EPA and DOT must judge whether a regulation is a "major" rule and, therefore, subject to the requirement that a Regulatory Impact Analysis (RIA) be prepared. Since EPA has determined that this regulation is not major, an RIA has not been prepared.

This regulation was submitted to the Office of Management and Budget (OMB) for review as required by Executive Order 12291. Any written comments from OMB and any EPA response to those comments are in the public docket for this rulemaking.

B. Reporting and Recordkeeping Requirements

This rule does not contain any information collection requirements which require approval by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 et seq.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act of 1980 requires federal agencies to identify potentially adverse impacts of federal regulations upon small entities. In instances where significant impacts are possible on a substantial number of these entities, agencies are required to perform a Regulatory Flexibility Analysis (RFA).

EPA has determined that the regulations proposed today will not have a significant impact on a substantial number of small entities. This regulation will affect Federal agencies and metropolitan planning organizations, which by definition are designated only for metropolitan areas with a population of at least 50,000.

Therefore, as required under § 605 of the Regulatory Flexibility Act, 5 U.S.C. 601 et seq., I certify that this regulation does not have a significant impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 51

Administrative practice and procedures, Air pollution control, Carbon monoxide, Intergovernmental relations, Lead, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

Dated: December 22, 1992.

William K. Reilly,

Administrator.

For the reasons set out in the preamble, title 40, chapter I, part 51 of the Code of Federal Regulations is proposed to be amended as follows.

PART 51—[AMENDED]

1. The authority citation for part 51 continues to read as follows:

Authority: 42 U.S.C. 7401(b)(1); 7407(d), 7410(k)(1), 7470–79, 7501–7508, and 7601(a)

2. Part 51 is amended by adding a new subpart T to read as follows:

Subpart T—Conformity to State or Federal Implementation Plans of Transportation Plans, Programs, and Projects Developed, Funded or Approved Under Title 23 U.S.C. or the Federal Transit Act

Sec.

51.390 Purpose.
51.391 Definitions.
51.392 Applicability.
51.393 Implementation plan revision.
51.394 Priority.
51.395 Frequency of conformity determinations.
51.396 Consultation.
51.397 Content of transportation plans.
51.398 Relationship of plan and TIP conformity with the NEPA process.
51.399 Fiscal constraints for transportation plans and TIPs.

Sec.
51.400 Criteria and procedures for determining conformity of transportation plans, programs, and projects.
51.401 Procedures for determining regional transportation-related emissions.
51.402 Procedures for determining localized CO and PM_{10} concentrations.
51.403 Exempt projects.
51.404 Projects exempt from regional emissions analyses.
51.405 Special provisions for nonattainment areas which are not required to demonstrate reasonable further progress and attainment.

Subpart T—Conformity to State or Federal Implementation Plans of Transportation Plans, Programs, and Projects Developed, Funded or Approved Under Title 23 U.S.C. or the Federal Transit Act

§ 51.390 Purpose.

The purpose of this subpart is to implement section 176(c) of the Clean Air Act (CAA), as amended (42 U.S.C. 7401 *et seq.*), and the related requirements of 23 U.S.C. 109(j), with respect to the conformity of transportation plans, programs, and projects which are developed, funded, or approved by the United States Department of Transportation (DOT), and by metropolitan planning organizations (MPOs) or other recipients of funds under title 23 U.S.C. or the Federal Transit Act (49 U.S.C. 1601 *et seq.*). This subpart sets forth policy, criteria, and procedures for demonstrating and assuring conformity of such activities to an applicable implementation plan developed pursuant to section 110 and part D of the CAA.

§ 51.391 Definitions.

Terms used but not defined in this subpart shall have the meaning given them by the CAA, titles 23 and 49 U.S.C., other Environmental Protection Agency (EPA) regulations, or other DOT regulations, in that order of priority.

Applicable implementation plan is defined in section 302(q) of the CAA and means the portion (or portions) of the implementation plan, or most recent revision thereof, which has been approved under section 110, or promulgated under section 110(c), or promulgated or approved pursuant to regulations promulgated under section 301(d) and which implements the relevant requirements of the CAA.

CAA means the Clean Air Act, as amended.

Cause or contribute to a new violation for a project means to cause or contribute to a new violation of a standard at a location or over a region which would otherwise not be in violation of the standard during the future period in question, if the project were not implemented.

Control strategy implementation plan is the applicable implementation plan which contains specific strategies for controlling the emissions of and reducing ambient levels of pollutants in order to satisfy CAA requirements for demonstrations of reasonable further progress and attainment.

Control strategy period with respect to particulate matter less than 10 microns in diameter (PM_{10}), carbon monoxide (CO), nitrogen dioxide (NO_2), and/or ozone precursors (volatile organic compounds and oxides of nitrogen), means that period of time after EPA approves control strategy implementation plans containing strategies for controlling PM_{10}, NO_2, CO, and/or ozone, as appropriate. This period ends when a State submits and EPA approves a request under section 107(d) of the CAA for redesignation to an attainment area.

Design concept means the type of facility identified by the project, e.g., freeway, expressway, arterial highway, grade-separated highway, reserved right-of-way rail transit, mixed-traffic rail transit, exclusive busway, etc.

Design scope means the design aspects which will affect the proposed facility's impact on regional emissions, usually as they relate to vehicle or person carrying capacity and control, e.g., number of lanes to be constructed or added, length of project, signalization, access control including approximate number and location of interchanges, preferential treatment for high-occupancy vehicles, etc.

DOT means the United States Department of Transportation.

Emissions budget is that portion of the total allowable emissions defined in the applicable implementation plan for the purpose of meeting reasonable further progress milestones or attainment or maintenance demonstrations, for any criteria pollutant or its precursors, allocated by the applicable implementation plan to highway and transit vehicles.

EPA means the Environmental Protection Agency.

FHWA means the Federal Highway Administration of DOT.

FHWA/FTA project, for the purpose of this subpart, is any highway or transit project which is proposed to receive funding assistance and approval through the Federal-Aid Highway program or the Federal mass transit program, or requires Federal Highway Administration (FHWA) or Federal Transit Administration (FTA) approval for some aspect of the project, such as connection to an interstate highway or deviation from applicable design standards on the interstate system.

FTA means the Federal Transit Administration of DOT.

Highway project is an undertaking to implement or modify a highway facility or highway-related program. Such an undertaking consists of all required phases necessary for implementation. For analytical purposes, it must be defined sufficiently to:

(1) Connect logical termini and be of sufficient length to address environmental matters on a board scope;

(2) Have independent utility or significance, i.e., be usable and be a reasonable expenditure even if no additional transportation improvements in the area are made; and

(3) Not restrict consideration of alternatives for other reasonably foreseeable transportation improvements.

Horizon year is a year for which the transportation plan describes the envisioned transportation system according to § 51.397 of this subpart.

Hot-spot analysis is an estimation of likely future localized CO and PM_{10} pollutant concentrations and a comparison of those concentrations to the national ambient air quality standards. Pollutant concentrations to be estimated should be based on the total emissions burden which may result from the implementation of a single, specific project, summed together with future background concentrations (to include emissions from facilities or actions which have completed environmental review) expected in the area. The total concentration must be estimated and analyzed at appropriate receptor locations in the area substantially affected by the project.

Incomplete data area means any ozone nonattainment area which EPA has classified, in 40 CFR part 81, as an incomplete data area.

Increase the frequency or severity means to cause a location or region to exceed a standard more often or to cause a violation at a greater concentration than previously existed and/or would otherwise exist during the future period in question, if the project were not implemented.

ISTEA means the Intermodal Surface Transportation Efficiency Act of 1991.

Maintenance area means any geographic region of the United States designated nonattainment pursuant to the CAA Amendments of 1990 and subsequently redesignated to attainment subject to the requirement to develop a maintenance plan under section 175A of the CAA Amendments.

Metropolitan planning organization (MPO) is that organization designated as being responsible, together with the State, for conducting the continuing, cooperative, and comprehensive planning process under 23 U.S.C. 134 and 49 U.S.C. 1607. It is the forum for cooperative transportation decision-making.

Milestone has the meaning given in section 182(g)(1) of the CAA.

National ambient air quality standards (NAAQS) are those standards established pursuant to section 109 of the CAA.

NEPA means the National Environmental Policy Act.

NEPA process completion, for the purposes of this regulation, with respect to FHWA or FTA, means the point at which there is a specific action to make a determination that a project is categorically excluded, to make a Finding of No Significant Impact, or to issue a record of decision on a Final Environmental Impact Statement under NEPA. Other recipients of funds under title 23 U.S.C. or the Federal Transit Act must establish and document project-level conformity in an environmental document submitted to FHWA or FTA prior to Federal completion of the NEPA process.

Nonattainment area means any geographic region of the United States which has been designated as nonattainment under section 107 of the CAA for any pollutant for which a national ambient air quality standard exists.

Non-federal TCM is any transportation control measure implemented by a State or local transportation agency which utilizes no Federal funding and requires no Federal approval.

Not classified area means any carbon monoxide nonattainment area which EPA has not classified.

Phase II of the interim period with respect to a pollutant or pollutant precursor means that period of time after the effective date of this rule, lasting until the relevant control strategy implementation plans are approved or promulgated by EPA.

Project means a highway project or transit project.

Regional-scale with respect to an actual or potential carbon monoxide, ozone, nitrogen dioxide, or particulate matter (less than 10 microns in diameter) national ambient air quality standard violation refers to a violation which occurs on a wide geographic scale due to emissions over a wide area, possibly over an extended period of time. This is in contrast to a hot-spot violation which occurs near a specific source and is predominantly due to recent emissions from that source being added to background concentrations.

Regionally significant, in the case of transportation facilities, means any facility with an arterial or higher functional classification, plus any other facility that serves regional travel needs (such as access to and from the area outside of the region, to major activity centers in the region, or to transportation terminals) and would normally be included in the modeling for the transportation network.

Rural area means any geographic region of the United States which has a population of less than 50,000 and which is not located within a Metropolitan Statistical Area or Consolidated Metropolitan Statistical Area as defined by the United States Census Bureau.

Standard means a national ambient air quality standard.

Submarginal area means any ozone nonattainment area which EPA has classified as submarginal in 40 CFR Part 81.

Transit is mass transportation by bus, rail, or other conveyance which provides general or special service to the public on a regular and continuing basis. It does not include school buses or charter or sightseeing services.

Transit project is an undertaking to implement or modify a transit facility or transit-related program; purchase transit vehicles or equipment; or provide financial assistance for transit operations. It would not include actions that are solely within the jurisdiction of local transit agencies, such as routes, schedules, or fares. It may consist of several phases. For analytical purposes, it must be defined inclusively enough to:

(1) Connect logical termini and be of sufficient length to address environmental matters on a broad scope;

(2) Have independent utility or independent significance, i.e., be a reasonable expenditure even if no additional transportation improvements in the area are made; and

(3) Not restrict consideration of alternatives for other reasonably foreseeable transportation improvements.

Transitional area means any ozone nonattainment area which EPA has classified as transitional in 40 CFR part 81.

Transportation control measure (TCM) is any measure that is specifically identified and committed to in the applicable implementation plan that is either one of the types listed in section 108 of the CAA, or any other measure for the purpose of reducing emissions or concentrations of air pollutants from transportation sources by reducing vehicle use or changing traffic flow or congestion conditions. Notwithstanding the above, vehicle technology-based, fuel-based, and maintenance-based measures which control the emissions from vehicles under fixed traffic conditions are not TCMs for the purposes of this regulation.

Transportation improvement program (TIP) is a program of transportation projects drawn from or consistent with the transportation plan and developed pursuant to title 23 U.S.C. and the Federal Transit Act.

Transportation plan is the long-range plan which identifies facilities that should function as an integrated metropolitan transportation system and is developed pursuant to title 23 U.S.C. and the Federal Transit Act. It gives emphasis to those facilities that serve important national and regional transportation functions, and includes a financial plan that demonstrates how the transportation plan can be implemented.

Transportation project is a highway project or a transit project.

§ 51.392 Applicability.

(a) *Action applicability.* Except as provided for in paragraph (c) of this section or § 51.403 of this subpart, conformity determinations are required for:

(1) The adoption, acceptance, or approval of transportation plans developed pursuant to 23 U.S.C. 134 or the Federal Transit Act by an MPO or DOT;

(2) The adoption, acceptance, or approval of TIPs developed pursuant to 23 U.S.C. 134 or the Federal Transit Act by an MPO or DOT; and

(3) The approval, funding, or implementation of FHWA/FTA projects.

(b) *Geographic applicability.* The provisions of this subpart shall apply in all nonattainment and maintenance areas for transportation-related criteria pollutants. The transportation-related criteria pollutants are ozone, carbon monoxide, nitrogen dioxide, and particles with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}). The provisions apply with respect to emissions of the criteria pollutants themselves and to emissions of precursor pollutants, i.e., volatile organic compounds and nitrogen oxides in ozone areas, nitrogen oxides in nitrogen dioxide areas, and volatile organic compounds, nitrogen oxides, and PM_{10} in PM_{10} areas.

(c) *Limitations.* Projects subject to this regulation for which the NEPA process and a conformity determination have

been completed by FHWA or FTA may proceed toward implementation without further conformity determinations. All phases of such projects which were considered in that action are also included, if those phases were for the purpose of funding, final design, right-of-way acquisition, construction, or any combination of these phases. However, any significant change in design concept and scope or a supplemental environmental document for air quality purposes shall also trigger a requirement for a new conformity determination of the project.

§ 51.393 Implementation plan revision.

States must submit to the EPA and DOT a revision to their implementation plan which contains criteria and procedures for DOT, MPOs and other State or local agencies to assess the conformity of transportation plans, programs, and projects, consistent with these regulations. This revision is to be submitted within 12 months of the promulgation of this rule. EPA will provide DOT with a 30-day comment period before taking action to approve or disapprove the submission.

§ 51.394 Priority.

When assisting or approving any action with air quality-related consequences, FHWA and FTA shall give priority to the implementation of those transportation portions of an applicable implementation plan prepared to attain and maintain the NAAQS. This priority shall be consistent with statutory requirements for allocation of funds among States or other jurisdictions. Where other important factors are a consideration, transportation measures which are not included in the applicable implementation plan can be funded or implemented; however, transportation measures in the applicable implementation plan must retain a high priority and funding decisions must promote their timely implementation to the extent that funds are available.

§ 51.395 Frequency of conformity determinations.

(a) *Transportation plans.* (1) Each new transportation plan must be found to conform based on the requirements of this rule and the applicable implementation plan prior to the transportation plan's adoption by the MPO.

(2) All transportation plan revisions must be found to conform based on the requirements of this rule and the applicable implementation plan, unless the revision merely adds or deletes exempt projects listed in § 51.403 of this subpart. The conformity determination must be based on the transportation plan and the revision taken as a whole.

(3) Conformity must be redetermined within 18 months of the following:

(i) [Insert date of publication of the final rule in the **Federal Register**];

(ii) Any implementation plan submitted by a State which meets the completeness criteria, is approved by EPA, and which:

(A) Establishes or revises a transportation-related emissions budget (as required by CAA sections 175A(a), 182(b)(1), 182(c)(2)(A), 182(c)(2)(B), 187(a)(7), 189(a)(1)(B), and 189(b)(1)(A); and sections 192(a) and 192(b), for nitrogen dioxide); or

(B) Adds, deletes, or changes TCMs; and

(iii) Any implementation plan promulgated by EPA which establishes or revises a transportation-related emissions budget or adds, deletes, or changes TCMs.

(4) In any case, conformity determinations must be made no less frequently than every three years.

(b) *Transportation improvement programs.* (1) A new TIP must be found to conform based on the requirements of this subpart and the applicable implementation plan prior to the TIP's approval.

(2) A TIP amendment requires a new conformity determination for the entire TIP prior to its approval, unless the amendment merely adds or deletes exempt projects listed in § 51.403 of this subpart.

(3) Conformity must be redetermined by the MPO and DOT within six months of the MPO's adoption of a new or revised transportation plan, unless the new or revised plan merely adds or deletes exempt projects listed in § 51.403 of this subpart.

(4) In any case, conformity determinations must be made no less frequently than every three years.

(c) *Projects.* FHWA/FTA projects must be found to conform prior to their approval.

§ 51.396 Consultation.

The implementation plan revision required under § 51.393 of this subpart shall include consultation procedures to be undertaken by MPOs, State departments of transportation, and DOT with State and local air quality agencies before making conformity determinations, and shall also include consultation procedures for ensuring an opportunity for public participation and review of draft transportation plans and TIPs prior to final action.

(a) *Interagency consultation procedures.* States shall provide in the implementation plan well-defined procedures whereby representatives of the MPOs; State and local air quality planning agencies; State and local transportation agencies; and other organizations with responsibilities for developing, submitting, or implementing provisions of an implementation plan required by the CAA consult with each other and with local or regional offices of EPA, FHWA, and FTA on the development of the implementation plan, the transportation plan, and the TIP. Interagency consultation procedures shall include, at a minimum:

(1) The roles and responsibilities assigned to each agency at each stage in the implementation plan development process and the transportation planning process, including technical meetings;

(2) The organizational level of regular consultation;

(3) A process for circulating (or providing ready access to) draft documents and supporting materials for comment prior to formal adoption or publication;

(4) The frequency of, or process for convening, consultation meetings and responsibilities for agenda formation;

(5) A process for escalating disagreements to higher organizational levels for settlement;

(6) The development of a list of the TCMs in the applicable implementation plan;

(7) A process involving the MPO, State and local air quality planning agencies, State and local transportation agencies, EPA, and DOT for evaluating and choosing a model (or models) and associated methods and assumptions to be used in hot-spot analyses and regional air quality modeling;

(8) A process involving the MPO, State and local air quality planning agencies, and State and local transportation agencies for evaluating events which will trigger new conformity determinations in addition to those triggering events established in § 51.395 of this subpart;

(9) A process involving the MPO, State and local air quality planning and transportation agencies, EPA, and DOT for evaluating whether projects otherwise exempted from meeting the requirements of this subpart (see §§ 51.403 and 51.404 of this subpart) should be treated as non-exempt in cases where potential adverse emissions impacts may exist for any reason;

(10) Where the metropolitan planning area does not include the entire nonattainment or maintenance area, a process involving the MPO and the State department of transportation for cooperative planning and analysis for

purposes of determining conformity of all projects outside the metropolitan area and within the nonattainment or maintenance area; and

(11) A process for consulting on the design, schedule, and funding of research and data collection efforts and regional air quality model development by the MPO (e.g., household/travel transportation surveys).

(b) *Public consultation procedures.* (1) Affected agencies making conformity determinations on plans, programs, and projects shall provide a reasonable opportunity for public review and comment prior to taking formal action on a conformity determination for all plans and TIPs, and on conformity determinations for projects where otherwise required by law.

(i) The agency shall publish the proposed procedures to be used for this requirement and allow 45 days for written public comment.

(ii) An agency which revises these procedures, as determined when the need arises by the agencies involved in the process, shall publish the new procedures and allow 45 days for written public comment.

(2) The MPO shall prepare a summary and analysis of written and oral comments before taking final action on conformity determinations subject to paragraph (b)(1) of this section.

(3) If the transportation plan or TIP to be submitted to DOT is significantly different than the one which was made available for public comment by the MPO and raises new material issues which interested parties could not reasonably have foreseen from the MPO notifications, then an additional opportunity for public comment on the revised plan or TIP must be provided.

(4) New public consultation procedures for plans and TIPs are being developed by DOT in response to requirements in the Intermodal Surface Transportation Efficiency Act of 1991 (ISTEA). When a DOT regulation on this subject is published in final form, its provisions will govern and the public consultation requirements contained in paragraph (b) of this section will cease to apply.

§ 51.397 Content of transportation plans.

(a) *Transportation plans adopted after January 1, 1995 in serious, severe, or extreme ozone nonattainment areas and in serious carbon monoxide nonattainment areas.* The transportation plan must specifically describe the transportation system envisioned for certain future years which shall be called horizon years.

(1) The agency or organization developing the transportation plan may choose any years to be horizon years, subject to the following restrictions:

(i) Horizon years may be no more than 10 years apart;

(ii) The first horizon year may be no more than 10 years from the base year used to validate the transportation demand planning model;

(iii) If the attainment year is in the time span of the plan, the attainment year must be a horizon year;

(iv) The last horizon year must be the last year of the plan's forecast period.

(2) For these horizon years:

(i) The plan shall quantify and document the demographic and employment factors influencing expected transportation demand, including land use forecasts, in accordance with implementation plan provisions and § 51.396 of this subpart;

(ii) The highway and transit system shall also be described in terms of the regionally significant additions or modifications to the existing transportation network which the plan envisions to be operational in the horizon years. Additions and modifications to the highway network shall be sufficiently identified to indicate intersections with existing regionally significant facilities, and to determine their effect on route options between transportation analysis zones. Each added or modified highway segment shall also be sufficiently identified in terms of its design concept and design scope to allow modeling of travel times under various traffic volumes, consistent with the modeling methods for area-wide transportation analysis in use by the MPO. Transit facilities, equipment, and services envisioned for the future shall be identified in terms of design concept, design scope, and operating policies sufficiently to allow modeling of their user volumes. The description of additions and modifications to the transportation network shall also be sufficiently specific to show that there is a reasonable relationship between expected land use and the envisioned transportation system; and

(iii) Other future transportation policies, requirements, services, and activities, including intermodal activities, shall be described.

(b) *Moderate areas reclassified to serious.* Ozone or CO nonattainment areas which are reclassified from moderate to serious must meet the requirements of paragraph (a) of this section within two years from the date of reclassification.

(c) *Transportation plans for other areas.* Transportation plans for other areas must meet the requirements of paragraph (a) of this section at least to the extent it has been the previous practice of the MPO to prepare plans which meet those requirements. Otherwise, transportation plans must describe the transportation system envisioned for the future specifically enough to allow determination of conformity according to the criteria and procedures of § 51.400 of this subpart.

(d) *Savings.* The requirements of this section supplement other requirements of applicable law or regulation governing the format or content of transportation plans.

§ 51.398 Relationship of plan and TIP conformity with the NEPA process.

The degree of specificity required in the transportation plan and the specific travel network assumed for air quality modeling do not preclude the consideration of alternatives in the NEPA process or other project development studies. Should the NEPA process result in a project with design concept and scope significantly different from that in the plan or TIP, the project must meet the criteria in § 51.400 of this subpart for projects not from a TIP before NEPA process completion.

§ 51.399 Fiscal constraints for transportation plans and TIPs.

(a) *Transportation plans.* The ISTEA requires that the transportation plan include a financial plan that demonstrates how the transportation plan can be implemented, indicates resources from public and private sources that are reasonably expected to be available throughout the plan's timeframe, and recommends any innovative financing techniques to finance needed projects and programs, including such techniques as value capture, tolls, and congestion pricing.

(b) *TIPs.* The ISTEA requires that full funding must be reasonably anticipated to be available for a project, or an identified phase of a project, within the time period contemplated for completion of the project prior to its inclusion in a TIP. The ISTEA also requires a financial plan that demonstrates how the TIP can be implemented, indicates resources from public and private sources that are reasonably expected to be made available for its implementation, and recommends any innovative financing techniques to finance needed projects and programs.

§ 51.400 Criteria and procedures for determining conformity of transportation plans, programs, and projects.

Transportation plans, programs, and projects must satisfy the following criteria and procedures in order to be

found to conform to the applicable implementation plan(s) for ozone, carbon monoxide (CO), nitrogen dioxide (NO_2), and particulate matter less than 10 microns in diameter (PM_{10}). The criteria for making conformity determinations may differ for plans, TIPs, and projects, for the time period in which the conformity determination is to be made, and for the relevant pollutant. An action may be found to conform to the purpose of the applicable implementation plan when the criteria in Table 1 are satisfied for the type of activity in the relevant time period, and when all applicable conformity requirements of implementation plans and of court orders for the area which pertain specifically to conformity determination requirements are fully satisfied. The procedures which correspond to each criterion in Table 1 are described in paragraphs (a) through (q) of this section.

TABLE 1.—CONFORMITY CRITERIA

Action	Criteria
Phase II of the Interim Period	
Transportation Plan	a,b,c(1),j,o.
TIP	a,b,c(2),m,p.
Project (From a conforming plan and TIP).	a,b,d,e,f,g,k.
Project (Not from a conforming plan and TIP).	a,b,c(3),d,f,g,k,n,q.
Control Strategy and Maintenance Periods	
Transportation Plan	a,b,c(1),h.
TIP	a,b,c(2),i.
Project (From a conforming plan and TIP).	a,b,d,e,f,g.
Project (Not from a conforming plan and TIP).	a,b,c(3),d,f,g,j.

(a) The conformity determination must be based on the latest planning assumptions.
(b) The conformity determination must be based on the latest emission estimation model available.
(c) The transportation plan, TIP, or project which is not from a conforming plan and TIP must provide for the timely implementation of TCMs from the applicable implementation plan.
(d) There must be a currently conforming transportation plan and currently conforming TIP at the time of project approval.
(e) The project must come from a conforming plan and program.
(f) The project must not cause or contribute to any new localized CO or PM_{10} violations or increase the frequency or severity of any existing CO or PM_{10} violations in CO and PM_{10} nonattainment and maintenance areas.
(g) The project must compy with PM_{10} control measures in the applicable implementation plan.
(h) The transportation plan must be consistent with the motor vehicle emissions budget(s) in the applicable implementation plan.
(i) The TIP must be consistent with the motor vehicle emissions budget(s) in the applicable implementation plan.
(j) Highway and transit projects which are not from a conforming plan and conforming TIP must be consistent with the motor vehicle emissions budget(s) in the applicable implementation plan.
(k) The project must eliminate or reduce the severity and number of localized CO violations in CO nonattainment areas.
(l) The transportation plan must contribute to emissions reductions in ozone and CO nonattainment areas.
(m) The TIP must contribute to emissions reductions in ozone and CO nonattainment areas.
(n) The project which is not from a conforming plan and TIP must contribute to emissions reductions in ozone and CO nonattainment areas.
(o) The transportation plan must not increase emissions in PM_{10} and NO_2 nonattainment areas.
(p) The TIP must not increase emissions in PM_{10} and NO_2 nonattainment areas.
(q) The project which is not from a conforming plan and TIP must not increase emissions in PM_{10} and NO_2 nonattainment areas.

(a) *The conformity determination must be based on the latest planning assumptions.* This criterion applies during all periods. It is satisfied if the conformity determination, with respect to all other applicable criteria in this section, is based upon the most recent planning assumptions in force at the time of the conformity determination. Assumptions must be derived from the estimates of current and future population, employment, travel, and congestion most recently developed by the MPO or other agency authorized to make such estimates and approved by the MPO. Conformity determinations must also include reasonable assumptions about transit service and increases in transit fares and road and bridge tolls over time.

(b) *The conformity determination must be based on the latest emission estimation model available.* This criterion applies during all periods. It is satisfied if the most current version of the motor vehicle emissions model specified by EPA for use in the preparation or revision of implementation plans in that State or area is used for the conformity analysis. EPA will consult with DOT to establish a grace period following the specification of any new model; any analysis begun during the grace period may use the previous version of the model. The grace period will be no less than three months and no more than 24 months after notice of availability is published in the **Federal Register**, depending on the degree of change in the model and the scope of re-planning likely to be necessary by MPOs in order to assure conformity. If the grace period will be longer than three months, EPA will announce the appropriate grace period in the **Federal Register**.

(c) *The transportation plan, TIP, or project which is not from a conforming plan and TIP must provide for the timely implementation of TCMs from the applicable implementation plan.* This criterion applies during all periods.

(1) For transportation plans, this criterion is satisfied if:

(i) The transportation plan, in describing the envisioned future transportation system, provides for the timely completion or implementation of all TCMs in the applicable implementation plan which are eligible for funding under title 23 U.S.C. or the Federal Transit Act, consistent with schedules included in the applicable implementation plan; and

(ii) Nothing in the transportation plan interferes with the implementation of any TCM in the applicable implementation plan.

(2) For TIPs, this criterion is satisfied if:

(i) An examination of the specific steps and funding source(s) needed to fully implement each TCM indicates that TCMs which are eligible for funding under title 23 U.S.C. or the Federal Transit Act are on or ahead of the schedule established in the applicable implementation plan, or, if such TCMs are behind the schedule established in the applicable implementation plan, the MPO and DOT have determined that past obstacles to implementation of the TCMs have been identified and have been or are being overcome, and that all State and local agencies with influence over approvals or funding for TCMs are giving maximum priority to approval or funding of TCMs over other projects within their control, including projects in locations outside the nonattainment or maintenance area.

(ii) If TCMs in the applicable implementation plan have previously been programmed for Federal funding but the funds have not been obligated and the TCMs are behind the schedule in the implementation plan, then the TIP cannot be found to conform if the funds intended for those TCMs are reallocated to projects in the TIP other than TCMs. If there are no other TCMs in the TIP, the funds may be reallocated to projects which are eligible for Federal funding under ISTEA's Congestion Mitigation and Air Quality Improvement Program.

(iii) Nothing in the TIP may interfere with the implementation of any TCM in the applicable implementation plan.

(3) For transportation projects which are not from a conforming transportation plan and TIP, this criterion is satisfied if the project does not interfere with the implementation of any TCM in the applicable implementation plan.

(d) *There must be a currently conforming transportation plan and currently conforming TIP at the time of project approval.* This criterion applies during all periods. It is satisfied if the current transportation plan and TIP have been found to conform to the applicable implementation plan by the MPO and DOT according to the procedures of this subpart. Only one conforming transportation plan may exist in an area at any time; conformity determinations of previous transportation plans expire once the current plan is found to conform by DOT.

(e) *The project must come from a conforming plan and program.* This

criterion applies during all periods. It is satisfied if there is a conforming transportation plan and program in place at the time of the conformity determination for the project.

(1) A project is considered to be from a conforming plan if:

(i) For projects which are required to be identified in the plan in order to satisfy § 51.397 of this subpart, the project is specifically included in the plan; or

(ii) For projects which are not required to be specifically identified in the plan, the project is identified in the plan, or is consistent with the policies and purpose of the plan and will not interfere with other projects specifically included in the plan.

(2) A project is considered to be from a conforming program if the project is included in the conforming TIP and the design concept and scope of the project were adequate at the time of the TIP conformity determination to determine its contribution to the TIP's regional emissions and have not changed significantly from those which were described in the TIP, or in a manner which would significantly impact use of the facility. Otherwise, the project must satisfy all criteria in Table 1 for a project not from a TIP.

(f) *The project must not cause or contribute to any new localized CO or PM_{10} violations or increase the frequency or severity of any existing CO or PM_{10} violations in CO and PM_{10} nonattainment and maintenance areas.* This criterion applies during all periods. It is satisfied if either:

(1) Consideration of local factors clearly demonstrates that new violations will not be created and the severity or number of existing violations will not be increased; or

(2) Hot-spot analysis demonstrates that no new local violations will be created and the severity or number of existing violations will not be increased as a result of the project.

(i) The model used shall be one selected as a result of consultation under § 51.396(a)(7) of this subpart.

(ii) Hot-spot analysis shall be performed according to the requirements of § 51.402 of this subpart.

(g) *The project must comply with PM_{10} control measures in the applicable implementation plan.* This criterion applies during all periods. It is satisfied if control measures (for the purpose of limiting PM_{10} emissions from the construction activities and/or normal use and operation associated with the project) contained in the applicable implementation plan are included in the plans, specifications, and estimates package for the project.

(h) *The transportation plan must be consistent with the motor vehicle emissions budget(s) in the applicable implementation plan.* This criterion applies during the control strategy and maintenance periods, except as provided in § 51.405 of this subpart. The total emissions of ozone precursors (VOC and NO_x), CO, or PM_{10} (and its precursors if the applicable implementation plan identifies transportation-related precursor emissions within the nonattainment area as a significant contributor to the PM_{10} nonattainment problem and establishes a budget for such emissions) expected from the transportation system as a result of implementing the new projects and activities contained in the plan or expected in the area must be estimated. This criterion is satisfied if the emissions are demonstrated to be less than or equal to each of the motor vehicle emissions budgets established in the applicable implementation plan for the milestone and attainment years. This demonstration requires that a regional emissions analysis be performed as follows:

(1) The emissions analysis methodology shall meet the requirements of § 51.401 of this subpart.

(2) The emissions analysis shall include all projects contained in the plan and all other regionally significant highway and transit projects expected in the nonattainment or maintenance area. The emissions analysis may not include for emissions reduction credit any TCMs which have been delayed beyond the scheduled date(s) until such time as implementation has been assured. TCMs which require a State or local regulation in order to be implemented and which are not specifically identified in the applicable implementation plan may not be included in the emissions analysis unless the regulation is already adopted by the enforcing jurisdiction.

(3) For areas with a transportation plan that meets the content requirements of § 51.397(a) of this subpart, the emissions analysis shall be performed for each horizon year. Emissions in milestone years which are between the horizon years may be determined by interpolation.

(4) For areas with a transportation plan that does not meet the content requirements of § 51.397(a) of this subpart, the emissions analysis shall be performed for years in the time span of the transportation plan provided they are not more than ten years apart and provided the analysis is performed for the last year of the plan's forecast period. If the attainment year is in the time span of the plan, the emissions analysis must also be performed for the attainment year. Emissions in milestone years which are between these analysis years may be determined by interpolation.

(i) *The TIP must be consistent with the motor vehicle emissions budget(s) in the applicable implementation plan.* This criterion applies during the control strategy and maintenance periods, except as provided in § 51.405 of this subpart. The total emissions of ozone precursors (VOC and No_x), CO, or PM_{10} (and its precursors if the applicable implementation plan identifies transportation-related precursor emissions within the nonattainment area as a significant contributor to the PM_{10} nonattainment problem and establishes a budget for such emissions) expected from the transportation system in general as a result of implementing the projects in the TIP and other expected projects must be estimated for the milestone and attainment years. Those estimates must be less than or equal to each of the motor vehicle emissions budgets for the milestone and attainment years in order for the TIP to conform.

(1) For areas with a conforming transportation plan that fully meets the content requirements of § 51.397(a) of this subpart, this criterion may be satisfied without additional regional analysis if:

(i) Each program year of the TIP is consistent with the Federal funding which may be reasonably expected for that year, and required State/local matching funds and funds for State/local funding-only projects are consistent with the revenue sources expected over the same period; and

(ii) The TIP is consistent with the transportation plan such that the regional emissions analysis already performed for the plan applies to the TIP also. This requires a demonstration that:

(A) The TIP contains all projects which must be started in the TIP's timeframe in order to achieve the highway and transit system envisioned by the plan in each of its horizon years;

(B) All TIP projects which add or modify regionally significant highway or transit facilities are part of the specific highway or transit system envisioned in the transportation plan's horizon years; and

(C) The design concept and scope of each regionally significant project in the TIP is not significantly different from that described in the transportation plan.

(iii) If the requirements in paragraphs (i)(1)(i) and (i)(1)(ii) of this section are not met, then:

(A) The TIP may be modified to meet those requirements; otherwise.

(B) The transportation plan must be revised so that the requirements in paragraphs (i)(1)(i) and (i)(1)(ii) of this section are met. Once the revised plan has been found to conform, this criterion is met for the TIP with no additional analysis except a demonstration that the TIP meets the requirements of (i)(1)(i) and (ii) of this section.

(2) For areas with a transportation plan that does not meet the content requirements of § 51.397(a) of this subpart, a regional emissions analysis must be performed for the TIP. This criterion may be satisfied if:

(i) The analysis methodology meets the requirements of § 51.401(b) of this subpart;

(ii) The analysis estimates emissions from the transportation system, including all projects contained in the proposed TIP, and all other regionally significant projects expected in the nonattainment or maintenance area in the timeframe of the transportation plan. The emissions analysis may not include for emissions reduction credit any TCMs which have been delayed beyond the scheduled date(s) established until such time as implementation has been assured. TCMs which require a State or local regulation in order to be implemented and which are not specifically identified in the applicable implementation plan may not be included in the emissions analysis unless the regulation is already adopted by the enforcing jurisdiction; and

(iii) The emissions analysis is performed for the last year of the plan's forecast period and any other years in the time span of the transportation plan which are not more than ten years apart. If the attainment year is in the time span of the plan, the emissions analysis must also be performed for the attainment year. Emissions in milestone years which are between these analysis years may be determined by interpolation.

(j) *Highway and transit projects which are not from a conforming plan and a conforming TIP must be consistent with the motor vehicle emissions budget(s) in the applicable implementation plan.* This criterion applies during the control strategy and maintenance periods, except as provided in § 51.405 of this subpart. It is satisfied if emissions from the implementation of the project, when added to the emissions from the projects in the conforming transportation plan and TIP and all other regionally significant projects expected in the area, do not exceed the motor vehicle emissions budget in the applicable implementation plan in the milestone or the attainment years.

(1) For areas with a conforming transportation plan that meets the content requirements of § 51.397(a) of this subpart:

(i) This criterion may be satisfied without additional regional analysis if the project is included in the conforming transportation plan, even if it is not specifically included in the latest conforming TIP. This requires a demonstration that:

(A) Allocating funds to the project will not delay the implementation of projects in the transportation plan or TIP which are necessary to achieve the highway and transit system envisioned by the plan in each of its horizon years;

(B) The project is not regionally significant or is part of the specific highway or transit system envisioned in the transportation plan's horizon years; and

(C) The design concept and scope of the project is not significantly different from that described in the transportation plan.

(ii) If the requirements of paragraph (j)(1)(i) of this section are not met, a regional emissions analysis must be performed as follows:

(A) The analysis methodology shall meet the requirements of § 51.401 of this subpart;

(B) The analysis shall estimate emissions from the transportation system, including the proposed project and all other regionally significant projects expected in the nonattainment or maintenance area in the timeframe of the transportation plan. The analysis must include emissions from all previously approved projects which were not from a plan and TIP. The emissions analysis may not include the emissions reduction credit any TCMs which have been delayed beyond the scheduled date(s) established until such time as implementation has been assured. TCMs which require a State or local regulation in order to be implemented and which are not specifically identified in the applicable implementation plan may not be included in the emissions analysis unless the regulation is already adopted by the enforcing jurisdiction; and

(C) The emissions analysis shall be performed for each horizon year. Emissions in milestone years which are between the horizon years may be determined by interpolation.

(2) For areas with a transportation plan that does not meet the content requirements of § 51.397(a) of this subpart, a regional emissions analysis must be performed for the project together with the conforming TIP and all other regionally significant projects expected in the nonattainment or maintenance area. This criterion may be satisfied if:

(i) The analysis methodology meets the requirements of § 51.401(b) of this subpart;

(ii) The analysis estimates emissions from the transportation system, including the proposed project, and all other regionally significant projects expected in the nonattainment or maintenance area in the timeframe of the transportation plan. The emissions analysis may not include for emissions reduction credit any TCMs which have been delayed beyond the scheduled date(s) established until such time as implementation is assured. TCMs which require a State or local regulation in order to be implemented and which are not specifically identified in the applicable implementation plan may not be included in the emissions analysis unless the regulation is already adopted by the enforcing jurisdiction; and

(iii) The emissions analysis is performed for the last year of the plan's forecast period and any other years in the time span of the transportation plan which are not more than ten years apart. If the attainment year is in the time span of the plan, the emissions analysis must also be performed for the attainment year. Emissions in milestone years which are between these analysis years may be determined by interpolation.

(k) *The project must eliminate or reduce the severity and number of localized CO violations in CO nonattainment areas.* This criterion applies during Phase II of the interim period only. It is satisfied with respect to existing localized CO violations if either:

(1) Consideration of local factors clearly indicates that existing CO violations will be eliminated or reduced in severity and number; or

(2) Hot-spot analysis indicates that existing CO violations will be eliminated or reduced in severity and number as a result of the project.

(i) The model used shall be one selected as a result of consultation under § 51.396(a)(7) of this subpart.

(ii) CO hot-spot analysis shall be performed according to the requirements of § 51.402 of this subpart.

(l) *The transportation plan must contribute to emissions reductions in ozone and CO nonattainment areas.* This criterion applies during Phase II of the interim period only, except as otherwise provided in § 51.405 of this subpart. It applies to the net effect on emissions of all projects contained in a new or revised transportation plan. This

criterion may be satisfied if the regional emissions analysis is performed as follows:

(1) Determine the analysis years for which emissions are to be estimated. The first analysis year shall be no later than the first milestone year (1995 in CO nonattainment areas and 1996 in ozone nonattainment areas). The second analysis year shall be either the attainment year for the area, or if the attainment year is the same as the first analysis year or earlier, the second analysis year shall be at least five years beyond the first analysis year.

(2) Define the "Baseline" scenario for each of the plan's horizon years to be the future transportation system that would result from current programs, composed of the following (except that projects listed in § 51.403 of this subpart need not be explicitly considered):

(i) All in-place regionally significant highway and transit facilities, services and activities;

(ii) All ongoing travel demand management or transportation system management activities; and

(iii) Completion of all regionally significant projects, regardless of funding source, which are currently under construction or are undergoing right-of-way acquisition; come from the first three years of the previously conforming plan and/or TIP; or have completed the NEPA process.

(3) Define the "Action" scenario for each of the plan's horizon years as the transportation system that will result in that year from the implementation of the proposed transportation plan, TIPs adopted under it, and other expected regionally significant projects in the nonattainment area. It will include the following (except that projects listed in § 51.403 of this subpart need not be explicitly considered):

(i) All facilities, services, and activities in the "Baseline" scenario;

(ii) Completion of all TCMs and regionally significant facilities, services, and activities specifically identified in the proposed plan which will be operational or in effect in the horizon year, except that regulatory TCMs may not be assumed to begin at a future time unless the regulation is already adopted by the enforcing jurisdiction or the TCM is identified in the applicable implementation plan;

(iii) All non-federal TCMs known to the MPO, but not included in the applicable implementation plan, which have been fully adopted and/or funded by the enforcing jurisdiction or sponsoring agency since the last conformity determination on the transportation plan;

(iv) The incremental effects of any non-federal TCMs known to the MPO, but not included in the applicable implementation plan, which were adopted and/or funded prior to the date of the last conformity determination on the transportation plan, but which have been modified since then to be more stringent or effective;

(v) Completion of all expected regionally significant highway and transit projects which are not from a conforming plan and TIP; and

(vi) Completion of all expected regionally significant non-FHWA/FTA highway and transit projects that have clear funding sources and commitments leading toward their implementation and completion by the horizon year.

(4) Estimate the emissions predicted to result in each analysis year from travel on the transportation systems defined by the "Baseline" and "Action" scenarios and determine the difference in regional VOC emissions (for all ozone nonattainment areas) and CO emissions (for CO nonattainment areas) between the two scenarios. The analysis must be performed for each of the plan's horizon years according to the requirements of § 51.401 of this subpart. The analysis must address the periods between the analysis years and the periods between 1990, the first milestone year (1996 for ozone and 1995 for CO), and the first of the analysis years. Emissions in milestone years which are between the analysis years may be determined by interpolation. The regional analysis must show that the "Action" scenario contributes to a reduction in emissions from the 1990 emissions by any nonzero amount.

(5) This criterion is met if the regional VOC emissions (for ozone nonattainment areas) and CO emissions (for CO nonattainment areas) predicted in the "Action" scenario are less than the emissions predicted from the "Baseline" scenario in each analysis year, and if this can reasonably be expected to be true in the periods between the first milestone year and the analysis years.

(m) *The TIP must contribute to emissions reductions in ozone and CO nonattainment areas.* This criterion applies during Phase II of the interim period only, except as otherwise provided in § 51.405 of this subpart. It applies to the net effect on emissions of all projects contained in a new or revised TIP. This criterion may be satisfied if a regional emissions impact analysis is performed as follows:

(1) Determine the analysis years for which emissions are to be estimated. The first analysis year shall be no later than the first milestone year (1995 in CO nonattainment areas and 1996 in ozone nonattainment areas). The second analysis year shall be either the attainment year for the area, or if the attainment year is the same as the first analysis year or earlier, the second analysis year shall be at least five years beyond the first analysis year.

(2) Define the "Baseline" scenario as the future transportation system that would result from current programs, composed of the following (except that projects listed in § 51.403 of this subpart need not be explicitly considered):

(i) All in-place regionally significant highway and transit facilities, services and activities;

(ii) All ongoing travel demand management or transportation system management activities; and

(iii) Completion of all regionally significant projects, regardless of funding source, which are currently under construction or are undergoing right-of-way acquisition; come from the first three years of the previously conforming TIP; or have completed the NEPA process.

(3) Define the "Action" scenario as the future transportation system that will result from the implementation of the proposed TIP and other expected regionally significant projects in the nonattainment area. It will include the following (except that projects listed in § 51.403 of this subpart need not be explicitly considered):

(i) All facilities, services, and activities in the "Baseline" scenario;

(ii) Completion of all TCMs and regionally significant facilities, services, and activities included in the proposed TIP, except that regulatory TCMs may not be assumed to begin at a future time unless the regulation is already adopted by the enforcing jurisdiction or the TCM is contained in the applicable implementation plan;

(iii) All non-federal TCMs known to the MPO, but not included in the applicable implementation plan, which have been fully adopted and/or funded by the enforcing jurisdiction or sponsoring agency since the last conformity determination on the TIP;

(iv) The incremental effects of any non-federal TCMs known to the MPO, but not included in the applicable implementation plan, which were adopted and/or funded prior to the date of the last conformity determination on the TIP, but which have been modified since then to be more stringent or effective;

(v) Completion of all expected regionally significant highway and transit projects which are not from a conforming plan and TIP; and

(vi) Completion of all expected regionally significant non-FHWA/FTA highway and transit projects that have clear funding sources and commitments leading toward their implementation and completion by the horizon year.

(4) Estimate the emissions predicted to result in each analysis year from travel on the transportation systems defined by the "Baseline" and "Action" scenarios, and determine the difference in regional VOC emissions (for all ozone nonattainment areas) and CO emissions (for CO nonattainment areas) between the two scenarios. The analysis shall consider the period between 1990 and the analysis years and shall meet the requirements of § 51.401 of this subpart.

(5) This criterion is met if the regional VOC emissions (for ozone nonattainment areas) and CO emissions (for CO nonattainment areas) predicted in the "Action" scenario are less than the emissions predicted from the "Baseline" scenario in each analysis year, and if this can reasonably be expected to be true in the period between the analysis years. The regional analysis must show that the "Action" scenario contributes to a reduction in emissions from the 1990 emissions by any nonzero amount.

(n) *The transportation project which is not from a conforming plan and TIP must contribute to emissions reductions in ozone and CO nonattainment areas.* This criterion applies during Phase II of the interim period only, except as otherwise provided in § 51.405 of this subpart. This criterion is satisfied if a regional emissions impact analysis is performed which meets the requirements of paragraph (1) of this section and which includes the plan and project in the "Action" scenario. If the project which is not from a conforming plan and TIP is a modification of a project currently in the plan or TIP, the "Baseline" scenario must include the project with its original design concept and scope, and the "Action" scenario must include the project with its new design concept and scope.

(o) *The transportation plan must not increase emissions in PM_{10} and NO_2 nonattainment areas.* This criterion is satisfied if it is demonstrated that when the projects in the transportation plan and TIP and all other regionally significant projects expected in the area are implemented, the transportation system's total highway and transit emissions of PM_{10} in a PM_{10} nonattainment area (and transportation-related precursors of PM_{10} in nonattainment areas for which the Administrator has made a finding or approved a finding in the applicable implementation plan that such precursor emissions from within the nonattainment area are a significant contributor to the PM_{10} nonattainment problem) and of NO_x in an NO_2 nonattainment area will not be greater than 1990 levels. This criterion applies only during Phase II of the interim period. This criterion may be satisfied if the regional emissions analysis is performed as follows:

(1) Determine the 1990 regional emissions of PM_{10} (for PM_{10} nonattainment areas) and NO_x (for NO_2 nonattainment areas) from highway and transit sources.

(2) Determine the analysis years for which emissions are to be estimated. The first analysis year shall be no later than the first milestone year (1995 in NO_2 nonattainment areas and 1996 in PM_{10} nonattainment areas). The second analysis year shall be either the attainment year for the area, or if the attainment year is the same as the first analysis year or earlier, the second analysis year shall be at least five years beyond the first analysis year.

(3) Define the "Action" scenario in each of the analysis years as the transportation situation that will result in that year from the implementation of the proposed transportation plan and TIPs adopted under it. It will include the following (except that projects listed in § 51.403 and § 51.404 of this subpart need not be explicitly considered):

(i) All in-place regionally significant highway and transit facilities, services and activities;

(ii) All ongoing travel demand management or transportation system management activities;

(iii) Completion of all regionally significant projects, regardless of funding source, which are currently under construction or are undergoing right-of-way acquisition; come from the first three years of the previously conforming plan and/or TIP; or have completed the NEPA process;

(iv) Completion of all TCMs and regionally significant facilities, services, and activities included in the proposed plan which will be operational or in effect in the horizon years, except that regulatory TCMs may not be assumed to begin at a future time unless the regulation is already adopted by the enforcing jurisdiction or the TCM is identified in the applicable implementation plan;

(v) All non-federal TCMs known to the MPO, but not included in the applicable implementation plan, which have been fully adopted and/or funded by the enforcing jurisdiction or sponsoring agency since the last conformity determination on the transportation plan;

(vi) The incremental effects of any non-federal TCMs known to the MPO, but not included in the applicable implementation plan, which were adopted and/or funded prior to the date of the last conformity determination on the transportation plan, but which have been modified since then to be more stringent or effective; and

(vii) Completion of all expected regionally significant non-FHWA/FTA highway and transit projects that have clear funding sources and commitments leading toward their implementation and completion by the horizon year.

(4) Estimate the emissions predicated to result in the attainment year from travel on the transportation systems defined the "Action" scenario.

(5) This criterion is met if the emissions from the "Action" scenario in the attainment year are no greater than 1990 emissions of PM_{10} (for PM_{10} nonattainment areas) or NO_x (for NO_2 nonattainment areas) from highway and transit sources.

(p) *The TIP must not increase emissions in PM_{10} and NO_2* nonattainment areas. This criterion is satisfied if it is demonstrated that when the projects in the transportation plan and TIP and all other regionally significant projects expected in the area are implemented, the transportation system's total highway and transit emissions of PM_{10} in a PM_{10} nonattainment area (and transportation-related precursors of PM_{10} in nonattainment areas for which the Administrator has made a finding or approved a finding in the applicable implementation plan that such precursor emissions from within the nonattainment area a significant contributor to the PM_{10} nonattainment problem) and of NO_x in an NO_2 nonattainment area will not be greater than 1990 levels. This criterion applies only during Phase II of the interim period. This criterion may be satisfied if a regional emissions impact analysis is performed as follows:

(1) Determine the 1990 regional emissions of PM_{10} (for PM_{10} nonattainment areas) and NO_x (for NO_2 nonattainment areas) from highway and transit sources.

(2) Determine the analysis years for which emissions are to be estimated. The first analysis year shall be no later than the first milestone year (1995 in NO_2 nonattainment areas and 1996 in PM_{10} nonattainment areas). The second analysis year shall be either the attainment year for the area, or if the attainment year is the same as the first analysis year or earlier, the second

analysis year shall be at least five years beyond the first analysis year.

(3) Define the "Action" scenario in each of the analysis years as the transportation situation that will result in that year from the implementation of the proposed transportation plan and TIPs adopted under it. It will include the following (except that projects listed in § 51.403 and § 51.404 of this subpart need not be explicitly considered):

(i) All in-place regionally significant highway and tranist facilities, services and activities;

(ii) All ongoing travel demand management or transportation system management activities;

(iii) Completion of all regionally significant projects, regardless of funding source, which are currently under construction or are undergoing right-of-way acquisition; come from the first three years of the previously conforming TIP; or have completed the NEPA process;

(iv) Completion of all TCMs and facilities, services, and activities included in the plan and the proposed TIP, except that regulatory TCMs may not be assumed to begin at a future time unless the regulation is already adopted by the enforcing jurisdiction or the TCM is identified in the applicable implementation plan;

(v) All non-federal TCMs known to the MPO, but not included in the applicable implementation plan, which have been fully adopted and/or funded by the enforcing jurisdiction or sponsoring agency since the last conformity determination on the TIP;

(vi) The incremental effects of any non-federal TCMs known to the MPO, but not included in the applicable implementation plan, which were adopted and/or funded prior to the date of the last conformity determination on the TIP, but which have been modified since then to be more stringent or effective; and

(vii) Completion of all regionally significant non-FHWA/FTA projects that have clear funding sources and commitments leading toward their implementation and completion by the analysis year.

(4) Estimate the emissions predicted to result in the attainment year from travel on the transportation systems defined by the "Action" scenario. If the attainment year and the analysis year do not coincide, the regional emissions analysis must be performed for the first analysis year after the attainment year. The attainment year may then be considered by interpolating between 1990 and the analysis year. The regional emissions analysis shall meet the requirements of § 51.401 of this subpart.

(5) This criterion is met if the emissions from the "Action" scenario in the attainment year are less than 1990 emissions of PM_{10} (for PM_{10} nonattainment areas) or NO_x (for NO_2 nonattainment areas) from highway and transit sources.

(q) *The transportation project which is not from a conforming plan and TIP must not increase emissions in PM_{10} and NO_2 nonattainment areas.* This criterion is met if a regional emissions impact analysis is performed which meets the requirements of paragraph (o) of this section and which includes the plan and project in the "Action" scenario. If the project which is not from a conforming plan and TIP is a modification of a project currently in the plan or TIP, the "Baseline" scenario must include the project with its original design concept and scope, and the "Action" scenario must include the project with its new design concept and scope.

§ 51.401 Procedures for determining regional transportation-related emissions.

(a) *Serious, severe, and extreme ozone nonattainment areas and serious carbon monoxide areas after January 1, 1995.* Estimates of regional transportation-related emissions used to support conformity determinations must be made according to procedures which meet the requirements in paragraphs (a)(1) through (5) of this section.

(1) A network-based transportation demand model or models relating travel demand and transportation system performance to land-use patterns, population demographics, employment, transportation infrastructure, and transportation policies must be used to estimate travel within the metropolitan planning area of the nonattainment area. Such a model shall possess the following attributes:

(i) The modeling methods and the functional relationships used in the model(s) shall in all respects be in accordance with acceptable professional practice, and reasonable for purposes of emission estimation;

(ii) The network-based model(s) must be validated against ground counts for a base year that is not more than 10 years prior to the date of the conformity determination. Land use, population, and other inputs must be based on the best available information and appropriate to the validation base year;

(iii) For peak-hour or peak-period traffic assignments, a capacity sensitive assignment methodology must be used;

(iv) Zone-to-zone travel times used to distribute trips between origin and destination pairs must be in reasonable agreement with the travel times which result from the process of assignment of trips to network links. Where use of transit currently is anticipated to be a significant factor in satisfying transportation demand, these times should also be used for modeling mode splits;

(v) Free-flow speeds on network links shall be based on empirical observations;

(vi) Peak and off-peak travel demand and travel times must be provided;

(vii) The model(s) must utilize and document a logical correspondence between the assumed scenario of land development and use and the future transportation system for which emissions are being estimated, but reliance on a formal land-use model is not specifically required;

(viii) A dependence of trip generation on the accessibility of destinations via the transportation system is not specifically required, unless the network model is capable of such determinations and the necessary information is available;

(ix) A dependence of regional economic and population growth on the accessibility of destinations via the transportation system is not specifically required, unless the network model is capable of such determinations and the necessary information is available; and

(x) Consideration of emissions increases from construction-related congestion is not specifically required.

(2) Highway Performance Monitoring System (HPMS) estimates of vehicle miles traveled shall be considered the primary measure of vehicle miles traveled within the portion of the nonattainment area and for the functional classes of roadways included in HPMS, for urban areas which are sampled on a separate urban area basis. A factor (or factors) shall be developed to reconcile and calibrate the network-based model estimates of vehicle miles traveled in the base year of its validation to the HPMS estimates for the same period, and these factors shall be applied to model estimates of future vehicle miles traveled. In this factoring process, consideration will be given to differences in the facility coverage of the HPMS and the modeled network description. Departure from these procedures is permitted with the concurrence of DOT and EPA.

(3) Reasonable methods shall be used to estimate nonattainment area vehicle travel on off-network roadways within the urban transportation planning area, and on roadways outside the urban transportation planning area.

(4) Reasonable methods must be used to estimate traffic speeds and delays in a

manner that is sensitive to the estimated volume of travel on each roadway segment represented in the network model.

(5) Ambient temperatures shall be consistent with those used to establish the emissions budget in the applicable implementation plan. Factors other than temperatures, for example the fraction of travel in a hot stabilized engine mode, may be modified after interagency consultation according to § 51.396 of this subpart if the newer estimates incorporate additional or more geographically specific information or represent a logically estimated trend in such factors beyond the period considered in the applicable implementation plan.

(b) *Other situations.* (1) Procedures which satisfy some or all of the requirements of paragraph (a) of this section shall be used in all areas not subject to paragraph (a) of this section in which those procedures have been the previous practice of the MPO.

(2) Regional emissions may be estimated by methods which do not explicitly or comprehensively account for the influence of land use and transportation infrastructure on vehicle miles traveled and traffic speeds and congestion. Such methods may extrapolate historical VMT or may project future VMT by considering growth in population and historical growth trends for vehicle miles travelled per person. These methods must also consider future economic activity, transit alternatives, and transportation system policies.

(c) *PM_{10} from construction-related fugitive dust.* (1) For areas in which the implementation plan does not identify construction-related fugitive PM_{10} as a contributor to the nonattainment problem, the fugitive PM_{10} emissions associated with highway and transit project construction are not required to be considered in the regional emissions analysis.

(2) In PM_{10} nonattainment and maintenance areas with implementation plans which identify construction-related fugitive PM_{10} as a contributor to the nonattainment problem, the regional PM_{10} emissions analysis shall consider construction-related fugitive PM_{10} and shall account for the level of construction activity, the fugitive PM_{10} control measures in the applicable implementation plan, and the dust-producing capacity of the proposed activities.

§ 51.402 Procedures for determining localized CO and PM_{10} concentrations.

(a) CO hot-spot analyses must be based on the applicable air quality models, data bases, and other requirements specified in the most recent version of the "Guideline on Air Quality Models (Revised)" (EPA publication No. 450/2–78–027R), including Supplements, which is hereby incorporated by reference as it exists on the date of approval (a notice of any change will be published in the **Federal Register**), in the following cases unless, after the interagency consultation process described in § 51.396(a) and with the approval of the EPA Regional Administrator, it is determined to be inappropriate:

(1) In locations, areas, or categories of sites which are identified in the SIP as sites of current violation or possible current violation; and

(2) Where use of the "Guideline" models is practicable and reasonable given the potential for violations.

(b) In cases other than those described in paragraphs (a)(1) and (a)(2) of this section, other quantitative methods may be used if they represent reasonable and common professional practice. Where both "Guideline" and non-"Guideline" models are available, "Guideline" models must be given the greatest consideration.

(c) CO hot-spot analyses must include the entire project, and may be performed only after the major design features which will significantly impact CO concentrations which have been identified. The background concentration must reflect emissions from all existing facilities and emissions expected from future projects which have completed environmental review.

(d) Hot-spot analysis assumptions must be consistent with those in the regional emissions analysis for those inputs which are required for both analyses.

(e) PM_{10} or CO mitigation or control measures shall be assumed in the hot-spot analysis only where there is a commitment in the NEPA document to incorporate such measures into the design and funding of the project.

(f) CO and PM_{10} hot-spot analyses are not required to consider construction-related activities which cause temporary and self-correcting increases in emissions. Each site which is affected by construction-related activities shall be considered separately, using established "Guideline" methods. Temporary and self-correcting increases are defined as those which occur only during the construction phase and last five years or less at any individual site.

§ 51.403 Exempt projects.

Notwithstanding the other requirements of this subpart, highway and transit projects of the types listed in Table 2 are exempt from the requirement that a conformity determination be made. Such projects may proceed toward implementation even in the absence of a conforming transportation plan and TIP. A particular action of the type listed in Table 2 is not exempt if the MPO in consultation with other agencies (see § 51.396(a)(8) of this subpart), the EPA, and the FHWA (in the case of a highway project) or the FTA (in the case of a transit project) concur that it has potentially adverse emissions impacts for any reason. States and MPOs must ensure that exempt projects do not interfere with TCM implementation.

Table 2.—Exempt Projects

Safety

Railroad/highway crossing
Hazard elimination program
Safer non-Federal-aid system roads
Shoulder improvements
Increasing sight distance
Safety improvement program
Traffic control devices and operating assistance other than signalization projects
Railroad/highway crossing warning devices
Guardrails, median barriers, crash cushions
Pavement resurfacing and/or rehabilitation
Pavement marking demonstration
Emergency relief (23 U.S.C. 125)
Fencing
Skid treatments
Safety roadside rest areas
Adding medians
Truck climbing lanes outside the urbanized area
Lighting improvements
Widening narrow pavements or reconstructing bridges (less than one travel lane)

Mass Transit

Operating assistance to transit agencies
Purchase of support vehicles
Rehabilitation of transit vehicles
Purchase of office, shop, and operating equipment for existing facilities
Purchase of operating equipment for vehicles (e.g., radios, fareboxes, lifts, etc.)
Construction or renovation of power, signal, and communications systems
Construction of small passenger shelters and information kiosks
Reconstruction or renovation of transit buildings and structures (e.g., rail or bus buildings, storage and maintenance facilities, stations, terminals, and ancillary structures)
Rehabilitation or reconstruction of track structures, track, and trackbed in existing rights-of-way

Purchase of new buses and rail cars to replace existing vehicles or for minor expansions of the fleet
Construction of new bus or rail storage/maintenance facilities categorically excluded in 23 CFR 771

Air Quality

Continuation of ride-sharing and van-pooling promotion activities at current levels
Bicycle and pedestrian facilities

Other

Engineering to assess social, economic, and environmental effects of the proposed action or alternatives to that action
Noise attenuation
Advance land acquisitions (23 CFR 712 or 23 CFR 771)
Acquisition of scenic easements
Plantings, landscaping, etc.
Sign removal

§ 51.404 Projects exempt from regional emissions analyses.

Notwithstanding the other requirements of this subpart, highway and transit projects of the types listed in Table 3 are exempt from regional CO or VOC emissions analysis requirements. The local effects of these projects with respect to CO or PM_{10} concentrations must be considered to determine if a hot-spot analysis is required prior to making a project-level conformity determination. These projects may then proceed to the project development process even in the absence of a conforming plan and TIP. A particular action of the type listed in Table 3 is not exempt from regional emissions analysis if the MPO in consultation with other agencies (see § 51.396(a)(8) of this subpart), the EPA, and the FHWA (in the case of a highway project) or the FTA (in the case of a transit project) concur that it has potential regional impacts for any reason.

Table 3.—Projects Exempt From Regional Emissions Analyses

Intersection channelization projects
Intersection signalization projects
Interchange reconfiguration projects
Changes in vertical and horizontal alignment
Truck size and weight inspection stations
Bus transfer terminals

§ 51.405 Special provisions for nonattainment areas which are not required to demonstrate reasonable further progress and attainment.

(a) *Application.* This section applies in the following areas:

(1) Rural ozone nonattainment areas;
(2) Marginal ozone areas;
(3) Submarginal ozone areas;
(4) Transitional ozone areas;
(5) Incomplete data ozone areas;
(6) Moderate CO areas with a design value of 12.7 ppm or less; and
(7) Not classified CO areas.

(b) *Default conformity procedures.* The criteria and procedures in § 51.400(l)–(n) of this subpart will remain in effect throughout the control strategy period for transportation plans, TIPs, and projects (not from a conforming plan and TIP) in lieu of the procedures in § 51.400(h)–(j) of this subpart, except as otherwise provided in paragraph (c) of this section.

(c) *Optional conformity procedures.* The State or MPO may voluntarily develop an attainment demonstration and corresponding motor vehicle emissions budget like those required in areas with high nonattainment classifications. In this case, the State must submit an implementation plan revision which contains that budget and attainment demonstration. Once EPA has approved this implementation plan revision, the procedures in § 51.400(h)–(j) of this subpart apply in lieu of the procedures in § 51.400(l)–(n) of this subpart.

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Part IV

Department of Commerce

Economic Development Administration

Economic Development Assistance Programs; Appropriations, 1993; Notice of Funds Availability

DEPARTMENT OF COMMERCE

Economic Development Administration

[Docket No. 921116-2316]

Economic Development Assistance Programs as Described in Public Law 102-395, Departments of Commerce, Justice, State, the Judiciary, and Related Agencies Appropriations, 1993; Availability of Funds

AGENCY: Economic Development Administration (EDA), Department of Commerce (DoC).

ACTION: Notice.

SUMMARY: The Economic Development Administration (EDA) announces its policies and application procedures for funds available in fiscal year 1993 to support projects designed to alleviate conditions of substantial and persistent unemployment and underemployment in economically distressed areas and regions of the Nation and to address economic dislocations resulting from sudden, severe job losses. The purpose of this announcement is to communicate to potential applicants for EDA funds the policies and procedures that will be used to administer the Agency's programs during fiscal year 1993.

I. General Policies

According to existing statutory criteria, areas containing approximately 90 percent of the U.S. population are eligible for EDA assistance which, in fiscal year 1993, totals approximately $217 million. Priority consideration for funding will be given only to those proposals having the greatest potential to benefit areas experiencing or threatened with substantial economic distress. EDA is particularly interested in projects located in authorized and designated enterprise zones. Distress may exist in a variety of forms, including exceptionally high levels of unemployment, extremely low income levels, large concentrations of low income families, low labor force participation rates, significant decline in per capita employment, substantial loss of population because of the lack of employment opportunities, unusually large numbers (or high rates) of business failures, farm foreclosures, sudden major layoffs or plant closures, and drastically reduced tax bases.

Potential applicants are responsible for demonstrating to EDA, through the provision of statistics and other appropriate information, the nature and level of the distress their efforts are intended to alleviate. In the absence of evidence of exceptionally high levels of distress, EDA funding is unlikely. In considering proposals to benefit severely distressed areas, EDA will give special consideration to those that address the needs of rural communities, particularly aid directed toward the economic diversification of such areas.

During FY 1993, EDA will place a special emphasis upon assisting projects that focus on exports, entrepreneurship, and technology initiatives including innovation, transfer, and commercialization to alleviate conditions of substantial and persistent unemployment and underemployment in economically distressed areas and regions, through the provision of grants for Public Works and Development Facilities, Technical Assistance, Economic Development Planning, and Economic Adjustment Assistance.

EDA recognizes that small communities experience impediments to economic development other than the traditional inadequacies of existing water, sewer and roadway systems; therefore, in fiscal year 1993, EDA will give consideration to projects that will assist an area to overcome a special development or infrastructure problem that is preventing employment growth and economic development from taking place. Such projects may involve, but are not limited to, activities designed to enhance the expansion of the service sector of the economy when that sector is deemed more growth oriented than the traditional industrial sector, or innovative projects designed for the development of publicly-owned telecommunications infrastructure when it can be demonstrated that such a project is needed to foster productivity or enhance economic growth within an EDA-designated area. Such proposals must be appropriately scaled and provide substantial and direct benefit to the local economy or otherwise enhance the economic prosperity of the area. EDA will consider providing assistance to demonstration type projects that are especially creative from an economic development standpoint and that leverage a substantial amount of nonfederal resources.

EDA expects substantial state and local support for proposed projects. Proposals that do not provide evidence of strong state and local leadership and financing are less likely to receive EDA assistance.

In the case of projects involving construction, EDA expects construction to be initiated and completed in a timely manner. Applicants are expected to anticipate predictable delays such as those caused by normal weather conditions, permits and approvals, legal complications, community disputes, land acquisition, etc., and account for them in developing project schedules. Projects which are likely to encounter significant delays will receive low funding priority. Projects that experience unreasonable delays following EDA approval may be terminated and the funds deobligated. These policies are consistent with EDA's objective of supporting activities that can begin to benefit local economies as soon as possible, thereby meeting the pressing development needs identified by project applicants. EDA expects those responsible for developing and managing projects to maximize the impact of the public funds by preparing and implementing projects as thoroughly and expeditiously as possible.

EDA funding will not be used directly or indirectly to assist employers who transfer one or more jobs from one commuting area to another. EDA nonrelocation requirements (13 CFR 309.3) apply to all grants involving construction, rehabilitation or repair under titles I, IV, IX, and section 301(f) of the Public Works and Economic Development Act of 1965 (Pub. L. 89-136, 42 U.S.C. 3121-3246h), as amended (including grants for Revolving Loan Funds, under title IX).

No award of Federal funds shall be made to an applicant who has an outstanding delinquent Federal debt until either:

1. The delinquent account is paid in full;

2. A negotiated repayment schedule is established and at least one payment is received, or

3. Other arrangements satisfactory to DoC are made.

Applicants may be subject to a pre-award accounting system survey by the Department of Commerce's Office of Inspector General, and fund recipients may be subject to audits or other inspections by the same office.

Applicants eligible for assistance because of membership in an economic development district must be active participants in the district's economic development planning process. EDA will evaluate applications for conformance with published statutory, regulatory, and policy requirements. Applications proposed for funding under these programs are subject to the requirements of Executive Order 12372, "Intergovernmental Review of Federal Programs."

An invitation to submit an application does not assure EDA funding. Factors that will be considered in evaluating proposals include if and to what extent the project meets the selection criteria.

Unsuccessful applicants will be notified of the status of their applications when the appropriate program funds have been awarded.

Processing time for proposals will depend upon the completeness of the information and supporting documents provided in the application at the time of submission. Proposals that require additional information from applicants or other sources will be returned to correct deficiencies and the official application receipt dates will be adjusted accordingly.

EDA will not approve projects that involve actual or potential conflict-of-interest situations. If EDA identifies or suspects a possible conflict-of-interest situation, or an appearance of such, application processing and/or grant award may be suspended and the burden will be on the applicant/grantee to take appropriate steps to eliminate the perception of a conflict of interest before application processing of the grant is resumed.

Recipients must agree that no funds made available by EDA shall be used, directly or indirectly, for paying attorneys' or consultants' fees in connection with securing awards made by the Government, such as, for example, preparation of the application. However, attorneys' and consultants' fees incurred for meeting award requirements, such as conducting a title search or preparing plans and specifications, may be eligible project costs and may be paid out of funds made available by EDA, if such costs are otherwise eligible.

Public Law 101–510, enacted November 5, 1990, section 1405, amending subchapter IV of chapter 15, title 31, United States Code, prescribes the rules for determining the availability of appropriations. Accordingly, grant funds obligated for a project will expire in five years from the fiscal year of the grant award.

Applicants must submit a completed Form CD–511, "Certifications Regarding Debarment, Suspension and Other Responsibility Matters; Drug-Free Workplace Requirements and Lobbying."

Recipients shall require applicants/bidders for subgrants, contracts, subcontracts, or other lower tier covered transactions at any tier under the award to submit, if applicable, a completed Form CD–512, "Certifications Regarding Debarment, Suspension, Ineligibility and Voluntary Exclusion-Lower Tier Covered Transactions and Lobbying" and disclosure form, SF–LLL, "Disclosure of Lobbying Activities." Form CD–512 is intended for the use of recipients and should not be transmitted to the Department. SF–LLL submitted by any tier recipient or subrecipient should be submitted to the Department in accordance with the instructions contained in the award document.

Prospective participants (as defined at 15 CFR part 26, section 105) are subject to 15 CFR part 26, "Nonprocurement Debarment and Suspension" and the related section of the certification form.

Grantees (as defined at 15 CFR part 26, section 605) are subject to 15 CFR part 26, subpart F, "Governmentwide Requirements for Drug-Free Workplace (Grants)" and the related section of the certification form.

Persons (as defined at 15 CFR part 28, section 105) are subject to the lobbying provisions of 31 U.S.C. 1352, "Limitation on use of appropriated funds to influence certain Federal contracting and financial transactions," and the lobbying section of the certification form which applies to applications/bids for grants, cooperative agreements, and contracts for more than $100,000, and loans and loan guarantees for more than $150,000, or the single family maximum mortgage limit for affected programs, whichever is greater. Any applicant that has paid or will pay for lobbying using any funds must submit an SF–LLL, "Disclosure of Lobbying Activities," as required under 15 CFR part 28, appendix B.

Applicants should be aware that a false statement on the application is grounds for denial or termination of funds and grounds for possible punishment by a fine or imprisonment as provided in 18 U.S.C. 1001.

All nonprofit and for-profit applicants are subject to a name check review process. Name checks are intended to reveal if any key individuals associated with the applicant have been convicted of, or are presently facing, criminal charges such as fraud, theft, perjury, or other matters which significantly reflect on the applicant's management, honesty or financial integrity.

Recipients and subrecipients are subject to all Federal laws and Federal and Departmental policies, regulations, and procedures applicable to Federal financial assistance awards.

Unsatisfactory performance under prior Federal awards may result in an application not being considered for funding.

If an application is selected for funding, EDA has no obligation to provide any additional future funding in connection with an award. Renewal of an award to increase funding or extend the period of performance is at the total discretion of the EDA.

Applicants should be aware that if they incur any costs prior to an award being made they do so solely at their own risk of not being reimbursed by the Government. Notwithstanding any verbal assurance that might have been received, there is no obligation on the part of EDA to cover pre-award costs.

The following material describes other policies and procedures associated with each of EDA's programs.

II. Program: Public Works and Development Facilities Assistance

(Catalog of Federal Domestic Assistance: 11.300 Economic Development Grants and Loans for Public Works and Development Facilities. 11.304 Economic Development Public Works Impact Program (PWIP))

Summary

Funds available under the Public Works and Development Facilities Program are used to finance projects that contribute to the economic development of distressed areas. Grants are authorized by titles I and IV of the Public Works and Economic Development Act of 1965, as amended (PWEDA), 42 U.S.C. 3131 and 42 U.S.C. 3171(a) (3).

Eligibility

Eligible applicants under this program include any state, or political subdivision thereof, Indian tribe, the Federated States of Micronesia, the Republic of the Marshall Islands, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa and the Commonwealth of the Northern Mariana Islands, or private or public nonprofit organization or association representing any redevelopment area or part thereof, if the project is located within an EDA-designated redevelopment area.

Redevelopment areas, other than those designated under the Public Works Impact Program, must have a current EDA-approved Overall Economic Development Program (OEDP). Political entities claiming eligibility under OEDPs developed by multicounty economic development organizations are expected to continue to participate actively in the organization. Further information on eligibility is available from EDA's regional offices. Nonprofit applicants are urged to seek the cooperation and support of units of local government and, when deemed appropriate by EDA, to have the local government serve as co-applicant for EDA assistance. This serves the purpose of ensuring the financial stability and continuity of the project, in the event that the nonprofit entity finds itself in a position of not having the financial resources to properly and efficiently administer,

operate, and maintain the EDA-assisted facility consistent with the provisions of 13 CFR 314–Property Management Standards.

Program Objective

The purpose of the Public Works Program is to assist communities with the funding of public works and development facilities that contribute to the creation or retention of private sector jobs and to the alleviation of unemployment and underemployment. Such assistance is designed to help communities achieve lasting improvement by stabilizing and diversifying local economies, and improving local living conditions and the economic development of the area. EDA emphasizes the alleviation of unemployment and underemployment among residents of the project area as a primary focus of this program. In view of the current rural distress, applications from rural communities will be reviewed with particular interest.

Funding Availability

Funds in the amount of $147.435 million are available for this program.

Funding Instrument

EDA may provide direct grants not to exceed 50 percent of the estimated cost of the project. However, under certain circumstances supplementary grants to augment the direct grant may be provided up to a maximum of 80 percent of the eligible project costs. But in no event shall the Federal participation exceed 80 percent of the aggregate cost of any such project, except in the case of a grant to an Indian Tribe, where EDA may waive the non-Federal share. Applicants are required to provide the local share from acceptable sources including, but not limited to cash, local government general obligation or revenue bonds, Community Development Block Grant (CDBG) entitlement funds or balance of state awards, Farmers Home Administration loans, and other public and private financing, including donations.

The local share need not be in hand at the time of application, however, the applicant must satisfy EDA that the funds will be available to provide the nonfederal share of the project.

The local share must not be encumbered in any way that would preclude its use consistent with the requirements of the grant. Priority will be given to applications which maximize the local share's percentage of the project cost. Supplementary grant assistance to finance over 50 percent of the project costs will be approved by EDA only for proposals in areas of high distress. Decisions on such supplementary grant assistance will be based on the nature of the project, the amount of fair user charges or other revenues the project may reasonably be expected to generate, and the relative needs of the area (see 13 CFR 305.5).

Selection Criteria

For both regular public works projects and Public Works Impact Program (PWIP) projects, priority consideration will be given to those which are the most competitive based upon the project selection criteria set forth below, that best meet the needs of eligible areas, and that are located in areas of severe economic distress.

A. Public Works Projects

Factors that will be taken into account in considering projects eligible under section 101(a)(1)(A)–(C) of PWEDA, 42 U.S.C. 3131(a)(1)(A)–(C), include if and to what extent the project:

1. Improves opportunities for the successful establishment or expansion of industrial or commercial facilities in the area where such project will be located.

2. Assists in creating or retaining private sector jobs in the near term and assists in the creation of additional long-term employment opportunities, provided the jobs are not transferred from any other area of the United States, and will result in a low cost-per-job in relation to total EDA cost.

3. Benefits the long-term unemployed and members of low-income families who are residents of the area to be served by the project.

4. Fulfills a pressing need of the area, or part thereof, in which it will be located.

5. Is consistent with the EDA approved Overall Economic Development Program (OEDP) for the area in which it is, or will be, located, and has broad community support.

6. Is supported by significant private sector investment.

7. Promotes exports, entrepreneurship, or technology initiatives including innovation, transfer and commercialization.

8. Has evidence of adequate local share of funds.

9. Supports developments taking place in designated enterprise zones, particularly in rural areas.

10. Demonstrates that necessary permits, land acquisitions, or options on land and rights-of-way have been obtained and that all other legal requirements of the application process have been satisfied.

11. Maximizes the amount of local, state or other Federal funding that is available.

12. Gives evidence of the ability to begin and complete construction in a timely manner in accordance with a schedule to be agreed upon by EDA and the applicant and included in the grant award. EDA discourages the start of construction prior to grant award and cautions that financial hardship may be experienced by applicants whose projects are not approved. EDA will require all applicants that request approval to proceed with construction prior to grant award to acknowledge that they are proceeding at their own risk and without recourse to EDA if the grant is not awarded or EDA requirements are not met. EDA also requires that compliance with environmental regulations be completed before construction begins. EDA's regional office must have time to complete its "Finding of No Significant Impact," and clearances must be obtained from appropriate state and Federal agencies. Furthermore, EDA may view the start of construction prior to grant award as an indication that the grant funds are not essential for the successful implementation of the project.

13. If located in an Economic Development Center (i.e., Growth Center) that has a stable economy with little distress, must include an employment plan that explains how new employment opportunities for residents of nearby highly distressed redevelopment areas will be provided.

B. Public Works Impact Program

Factors that will be considered in the evaluation of projects under the Public Works Impact Program (PWIP) authorized by section 101(a)(1)(D) of PWEDA, 42 U.S.C. 3131(a)(1)(D), include if and to what extent the project:

1. Directly assists in creating immediate useful work (i.e., construction jobs) for the unemployed and underemployed residents in the project area;

2. Improves the economic or community environment in areas of severe economic distress;

3. Includes a specific plan (i.e., PWIP Employment Strategy) for hiring the unemployed and underemployed persons from the project area to work on the construction of the project; EDA will evaluate all plans to ensure that they contain a logical explanation of how the employment objectives will be met;

4. Assists in providing long-term employment opportunities or other economic benefits for the unemployed and underemployed in the project area;

5. Primarily benefits low-income families by providing essential community services, or satisfying a pressing public need;

6. In addition to the requirement for regular public works projects, as contained in paragraph A, can begin construction quickly (normally within 120 days after acceptance of the grant by the applicant);

7. Has substantial labor intensity, where labor intensity is the proportion of labor costs to the total project costs; and

8. Promotes exports, entrepreneurship or technology initiatives including innovation, transfer, and commercialization.

C. Industrial Park Projects

Applications proposing projects that will primarily serve an industrial park or site will be evaluated on such additional factors as:

1. A detailed analysis of existing industrial park capacity and utilization; occupancy rates for existing developed industrial parks currently available within a 25-mile radius of the project site. For cities with populations over 50,000, the prescribed area may be determined by an analysis of industrial sites within an established industrial area, which may be less than a 25-mile radius. Contact the economic development representative (EDR) for the area or the appropriate EDA regional office for guidance.

2. Commitments in writing from identified tenants to expand existing operations or to locate in the industrial park or site. Commitments must include a description of the industry, the number of jobs created or saved, an implementation schedule, and the relationship of the commitment to the requested grant assistance.

3. The existence of a documented marketing strategy and demonstrated financial ability to market space in the industrial park or site. Strong emphasis will be placed upon this requirement.

Construction Project Implementation

As indicated in the first section of this Notice, EDA expects construction projects to be initiated and completed in a timely manner and in accordance with the schedule agreed upon in the grant documentation. The recipient will be responsible for promptly notifying EDA of any events that prevent adherence to the approved schedule. The recipient must provide an explanation of why the events were beyond its ability to predict or control and obtain EDA's approval of changes in the schedule prior to proceeding with project implementation. EDA expects recipients to anticipate predictable delays (such as those caused by land acquisition problems, local financing requirements, normal weather conditions in the area, acquisition of state permits and approvals, and known public objections to the project), and to take them into account in preparing the project schedule. Recipients who fail to comply with project schedules are subject to grant suspension or termination.

Under most circumstances, EDA will not provide additional funds to finance cost overruns that occur during project implementation.

Proposal Submission Procedures

To establish the merits of project proposals, interested parties should first contact the economic development representative for the area (see listing in section X). The economic development representative for the area will provide a preapplication form (ED–101P, OMB Control No. 0610–0011) and arrange for conferences to discuss the proposal. EDA will screen proposals before inviting the submission of an application. As previously mentioned, an invitation does not assure EDA funding. Proposals will be evaluated based upon:

1. Conformance with statutory and other legal requirements and with the selection criteria mentioned above;

2. The merits of the proposal in addressing the economic development needs of the eligible area; and

3. The availability of program funds.

Processing time for project proposals depends upon the completeness of information and supporting documents provided in the preapplication form at the time of submission. Project proposals that require additional information from applicants or other sources will be returned to correct deficiencies and the official application receipt dates will be adjusted accordingly.

Application Procedures

Following a review of project proposals, EDA will invite entities whose projects are selected for consideration to submit applications. The application will include a form ED–101A, as approved by the Office of Management and Budget Control No. 0610–0011. The demand for public works assistance is expected to exceed available funding. Therefore, to avoid having incomplete proposals delay other more timely grant awards, a 120-day time restriction will apply to invited applications for resolving application deficiencies. Applications that cannot be recommended for approval within 120 days of receipt in a regional office because of unresolved issues will be returned to the applicants. Such applications may be reconsidered at a future date, but must compete with other proposals at that time.

Previous Applications

Project applications invited, but not funded in FY 1992, remain eligible for funding consideration. Applications received prior to the date of this Notice will be processed and evaluated in accordance with the project selection criteria published for FY 1992 and current legal requirements. Those applications received on or after the date of this Notice must be consistent with the project selection criteria and requirements published in this Notice. Applicants whose projects were invited but not submitted to EDA in FY 1992 should contact the appropriate EDA regional office regarding forms to be used for FY 1993.

Further Information

For further information contact the appropriate EDA regional office or economic development representative for your area (see section X of this Notice).

III. Program: Local Technical Assistance

(Catalog of Federal Domestic Assistance: 11.303 Economic Development—Technical Assistance)

Summary

Funds under the Local Technical Assistance Program are awarded to eligible applicants to help assure the successful initiation and implementation of area, state, and regional development efforts designed to alleviate economic distress. This program is authorized under section 301(a) of the Public Works and Economic Development Act of 1965, as amended, 42 U.S.C. 3151(a).

Eligibility

Eligible applicants for Local Technical Assistance grants or cooperative agreements include public or private nonprofit national, state, area, district, or local organizations; public and private colleges and universities; Indian tribes, local governments, and state agencies. In certain circumstances, applications may be considered from other applicants such as private individuals, partnerships, firms, and corporations.

Program Objective

The Local Technical Assistance Program is designed to help alleviate or prevent conditions of excessive

unemployment or underemployment and problems of economically distressed populations in rural and urban areas.

Funding Availability

Funds in the amount of $600,000 are available for the Local Technical Assistance Program. (Note: EDA generally will limit its funding for a proposed Local Technical Assistance project to $25,000.)

Funding Instrument

EDA will provide grants and cooperative agreements not to exceed 75 percent of the proposed project costs. Applicants are expected to provide the remaining share, preferably in cash. The Assistant Secretary may waive all or part of the 25 percent share of technical assistance grants, if he/she determines that the nonfederal share is not reasonably available because of the critical nature of the situation requiring technical assistance or for other good cause.

Project Duration

Assistance will be for the period of time required to complete the scope of the work. This typically does not exceed twelve months.

Selection Criteria

Preference will be given to Local Technical Assistance proposals which:

1. Show that the proposed project will lead to the near-term (between one and five years) generation or retention of private sector jobs.
2. Support the efforts of state and local organizations and institutions, including nonprofit development groups, to undertake and promote effective economic development programs targeted to people and areas in distress.
3. Stimulate significant private and nonfederal public investment for economic development purposes.
4. Benefit severely distressed areas, particularly rural counties and communities.
5. Demonstrate innovative approaches to stimulating economic development in depressed areas. EDA is particularly interested in receiving innovative proposals in the following areas:
   a. Export development as an economic development strategy;
   b. Assistance to business in uses of technology initiatives including innovation, transfer, and commercialization;
   c. Minority business development in distressed areas;
   d. Tourism;
   e. Rural enterprise zones;
   f. Linkages in economic development and environmental goals; and
   g. Entrepreneurship.
6. Are consistent with the EDA approved Overall Economic Development Program (OEDP) for the area in which the projects are located and have been recommended by the OEDP Committee (if appropriate to the nature of the project).
7. Present an appropriate and clear project design.
8. Are proposed by organizations with the capacity, qualifications and staff necessary to undertake the intended activities.
9. Present a reasonable, itemized budget for the proposed activities.

Pre-Application Procedures

Parties seeking support for Local Technical Assistance projects should contact the economic development representative (EDR) for information before preparing a proposal. (See EDR listing in section X of this announcement.)

EDA will evaluate all proposals as they are received and invite applications for those which best satisfy the selection criteria. An invitation does not, however, assure EDA funding.

Potential applicants should submit one original and two copies of a brief and concise proposal.

Proposal Submission Procedures

Potential applicants must submit to the appropriate EDR proposals that include:

1. A cover page giving a short descriptive project title, the name and address of the applicant organization, the name and telephone number of the project director, the project duration, the amount of EDA funds requested, and the program (Local Technical Assistance) that would provide the funds;
2. A brief description of the project;
3. A brief explanation of why the project is needed and its objectives;
4. A work plan showing different phases of the project and their timing;
5. A detailed budget showing cost breakdowns, with EDA-funded and non-EDA-funded costs presented in separate columns and with the EDA-funded costs equaling to the total shown on the cover page.

Application Procedures

The appropriate EDA regional office will invite entities whose proposals for Local Technical Assistance projects are selected for further consideration to submit application packages. The application will include a Standard Form–424 (OMB Control No. 038–0043).

Further Information

For further information about Local Technical Assistance projects contact the appropriate EDR. (See EDR listing in section X of this announcement.)

IV. Program: National Technical Assistance

(Catalog of Federal Domestic Assistance: 11.303 Economic Development—Technical Assistance)

Summary

Funds under the National Technical Assistance Program are awarded to eligible applicants who will offer assistance to local, regional and state organizations, and/or conduct demonstrations of and disseminate information about innovative development techniques designed to alleviate economic distress. This program is authorized under section 301(a) of the Public Works and Economic Development Act of 1965, as amended, 42 U.S.C. 3151(a).

Eligibility

Eligible applicants for National Technical Assistance grants or cooperative agreements include public or private nonprofit national, state, area, district, or local organizations; public and private colleges and universities; Indian tribes, local governments, and state agencies. In certain circumstances, applications may be considered from other eligible applicants such as private individuals, partnerships, firms, and corporations.

Program Objective

The National Technical Assistance Program is designed to help alleviate or prevent conditions of excessive unemployment or underemployment and problems of economically distressed populations.

Funding Availability

Funds in the amount of $830,000 are available for the National Technical Assistance Program.

Funding Instrument

EDA will provide grants and cooperative agreements not to exceed 75 percent of proposed project costs. Applicants are expected to provide the remaining share. In cases where EDA issues a Solicitation of Applications, an applicant's share may not be required. The Assistant Secretary may waive all or part of the 25 percent nonfederal share of technical assistance grants, if he/she determines that the nonfederal share is not reasonably available because of the critical nature of the

situation requiring technical assistance or for other good cause.

Project Duration

Assistance will be for the period of time required to complete the scope of the work. Generally, this will not exceed fifteen months.

Selection Criteria

Preference will be given to those Technical Assistance proposals which:

1. Do not depend upon further EDA or other Federal funding assistance to achieve results.
2. Support the capability of state and local organizations and institutions, including nonprofit development groups, to undertake and promote effective economic development programs targeted to people and areas in distress.
3. Stimulate significant private and nonfederal public investment for economic development purposes.
4. Benefit severely distressed areas.
5. Demonstrate innovative approaches to stimulating economic development in depressed areas. EDA is particularly interested in receiving innovative proposals in the following areas:
   a. Assistance to business in implementing technology initiatives including innovations, transfer, and commercialization;
   b. Exports;
   c. Entrepreneurship;
   d. Tourism;
   e. Rural enterprise zones; and
   f. Linkages in economic development and environmental goals.
6. Present an appropriate and clear project design.
7. Are proposed by organizations with the capacity, qualifications, and staff necessary to undertake the intended activities.
8. Present a reasonable, itemized budget for the proposed activities.

Pre-Application Procedure

Potential applicants should submit one original and two copies of a brief and concise proposal which should not exceed 20 pages. Vita and capability information may be appended.

Proposals should include:

1. A cover page giving a short descriptive project title, the name and address of the performing organization, the name and telephone number of the project director, the project duration, the amount of EDA funds requested, and the program (National Technical Assistance) that would provide the funds;
2. A brief scope-and-objectives section indicating why the project is needed, giving its objectives, and providing a capsule description of the project;
3. A more detailed description of the project and its methodology;
4. A work plan showing different phases of the project and their timing;
5. A detailed budget showing cost breakdowns, with EDA-funded and non-EDA-funded costs presented in separate columns and with the EDA-funded costs adding to the total shown on the cover page;
6. Résumés for the project director and principal staff; and
7. A corporate or institutional capability statement, where appropriate.

Proposals should be submitted to the Director, Technical Assistance and Research Division, Economic Development Administration, room 7315, U.S. Department of Commerce, Washington, DC 20230.

Application Procedures

The Technical Assistance and Research Division will invite entities whose proposals for National Technical Assistance projects are selected for further consideration to submit application packages. Such invitation, however, does not assure EDA funding. The application will include a Standard Form-424 (OMB Control No. 038–0043).

Eligibility for Specific Solicitations

EDA may, during the course of the year, identify additional specific economic development technical assistance activities. Organizations and individuals interested in being invited to respond to Solicitations of Applications (SOAs) to conduct such work should submit information on their capabilities and experience to the Director, Technical Assistance and Research Division, Economic Development Administration, room 7315, U.S. Department of Commerce, Washington, DC 20230.

Further Information

For further information about National Technical Assistance projects contact the National Technical Assistance Coordinator, telephone (202) 482–2127.

V. Program: University Center Technical Assistance Projects

(Catalog of Federal Domestic Assistance: 11.303 Economic Development—Technical Assistance)

Summary

Funds for basic university center projects are used as seed money to help selected colleges and universities mobilize their own and other resources to assist in the economic development of distressed areas. The efforts of university centers should focus on helping public bodies, nonprofit organizations and businesses plan and implement activities designed to generate jobs and income. In addition, funds may be used for projects which promote the goals of the University Center Program in other ways that demonstrate innovative economic development. Support for these types of projects is authorized under section 301(a) of the Public Works and Economic Development Act of 1965, as amended, 42 U.S.C. 3151(a).

Eligibility

Eligible applicants for university center grants and cooperative agreements are public and private colleges and universities, associations representing such institutions, and other organizations with expertise in University Center Program issues.

Program Objective

The objective of these projects is to enable colleges and universities to contribute to overall economic development by using their resources to provide technical assistance that will alleviate or prevent conditions of excessive unemployment or underemployment and problems of distressed populations in individual states or substate areas.

Funding Availability

Funds in the amount of $7.570 million are available for university center projects. It is expected that continuation grants for existing centers will use all of this amount.

Funding Instrument

EDA will provide grants or cooperative agreements not to exceed 75 percent of the proposed project costs.

Project Duration

Grants will be for a one-year period.

Selection Criteria

University center proposals (for both continuation and initial grants) must present a clear description of the economy of the proposed service area, its economic development needs, and the activities to be carried out with the requested funding. The work program for the university center must be structured under the following categories:

1. Providing technical assistance (which must be the major emphasis of the program),
2. Conducting applied research, and
3. Disseminating results of university center activities.

For this program, EDA defines technical assistance as any activity

undertaken in response to a direct request for help from a client outside the sponsoring institution, and applied research is defined as any activity undertaken by the university center at its own initiative.

Each proposal must contain quantitative and qualitative evaluation criteria for each activity listed under the above three work program categories. These criteria, when accepted by EDA, will be used to judge the performance of the university center.

Each university center that received funding in fiscal year 1992 was required to provide these evaluation criteria for its work program. EDA will give significant weight in assessing the overall performance of a university center to the degree that the university center met these quantitative and qualitative evaluation criteria.

If one or more university centers fails to qualify for a fiscal year 1993 continuation grant, EDA will hold an open competition for those funds in the appropriate regional office. In judging proposals for initial grants under an open competition, EDA will consider the:

1. Quality of the proposed work program;
2. Degree to which the work program is focused on providing technical assistance to organizations outside the sponsoring institution (i.e., on providing technical assistance);
3. Presence of a methodology for recognizing/rewarding the participation of faculty and students in the work program;
4. Presence of a five-year financial plan for the university center;
5. Commitment, as evidenced by financial support and other resources, of the university leadership at the highest levels to the mission and purpose of the university center;
6. Capacity of the institution and the university center to provide the proposed technical and other types of assistance to jurisdictions and organizations within the service area;
7. Degree to which the proposal complements and supports the local, regional or state economic development strategies in the service area;
8. Extent to which the center proposes to target its assistance to the economically-distressed sections of its proposed service area; and
9. Presence of other technical assistance providers in the proposed service area including Small and Minority Business Development Centers (SBDCs and MBDCs) and Trade Adjustment Assistance Centers.

Institutions seeking continuation or initial grants under this program should realize that EDA will not award university center funds to provide small business counseling or management assistance in areas serviced by an SBDC or an MBDC.

All applicants should realize that EDA limits the indirect cost rate that may be charged to grants under this program to 20 percent of total direct costs or the institution's negotiated indirect cost rate, whichever is less. Institutions with indirect cost rates above 20 percent may not use the amount above the 20 percent level as part of the nonfederal share.

Proposals for other projects that meet the goals of the University Center Program will be judged on similar factors. These include the potential impact of the project on distressed areas, the quality of the proposed work program, and the qualifications of the applicant to carry it out.

Depending on the availability of funds, EDA may hold a competition for short-term (one to three years) incentive grants. This competition will be open to all currently and previously funded centers, except those whose funding was discontinued because of poor performance.

Funding Policy

Public Law 102–395, the Department of Commerce fiscal year 1993 Appropriations Act, provides $7.570 million for this program, a $154,000 reduction from the fiscal year 1992 amount. The accompanying Conference Report directs EDA to award these funds to university centers that received funding in fiscal year 1992 and to make any adjustments in individual funding levels equitably among all of the university centers.

A successful applicant under any such open competition will be eligible for funding under the program for a five year period, subject to the continued availability of program funds and an annual determination by EDA of satisfactory performance by the university center. Any institution receiving an initial university center grant in fiscal year 1993 will be required to provide a nonfederal share equal to 25 percent of the total project costs for the first year. If funding is available, for the second through the fifth years, the institution should increase its nonfederal share to equal the university center grant.

Proposal Submission Procedures for Continuation Grants

Each existing university center will be notified by the appropriate regional office of its eligibility for continuation funding. At that time, university centers eligible for continuation funding will be notified of the amount of the required nonfederal share and provided with additional program guidance.

Proposal Submission Procedures for Basic Grants

Institutions seeking funding for a university center should submit a proposal describing the activities to be carried out with the grant funds to the appropriate EDA regional office or to the EDR for the area. (See EDA regional office and EDR list in Section X of this announcement.)

Further Information

For further information about University Center Technical Assistance projects contact the appropriate EDR or regional office (listing in Section X of this announcement) or the University Center Coordinator, Technical Assistance and Research Division, Economic Development Administration, room 7315, U.S. Department of Commerce, Washington, DC 20230; telephone (202) 482–2127.

VI. Program: Planning Assistance for Economic Development Districts, Indian Tribes, and Redevelopment Areas

(Catalog of Federal Domestic Assistance: 11.302 Economic Development—Support for Planning Organizations)

Summary

Funds under the District, Indian, and Area Planning Program are awarded to defray administrative expenses in support of the economic development planning efforts of economic development districts (Districts), redevelopment areas (Areas) and Indian tribes. This program is authorized under section 301(b) of the Public Works and Economic Development Act of 1965, as amended, 42 U.S.C. 3151(b).

Eligibility

Eligible applicants are economic development districts, redevelopment areas, organizations representing redevelopment areas (or parts of such Areas), Indian tribes, organizations representing multiple Indian tribes, the Federated States of Micronesia, the Republic of the Marshall Islands, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands.

Program Objective

The primary objective of planning assistance for administrative expenses under section 301(b) is to support the formulation and implementation of

economic development programs designed to create or retain full-time permanent jobs and income, particularly for the unemployed and underemployed in the most distressed areas served by the applicant. Planning activities supported by these program funds must be part of a process involving significant leadership by public officials and private citizens.

Funding Availability

Funds in the amount of $20.254 million are available in two categories: Districts/Areas (Category A)—$17.353 million; and Indian tribes (Category B)—$2.901 million.

Funding Instrument

Grant assistance can be provided for up to 75 percent of project costs for Category A grants with the applicant required to provide the remaining share from local (non-federal) sources. Category B grant assistance may be provided for up to 100 percent of project costs.

Project Duration

Assistance will normally be for a period of twelve months.

Selection Criteria

EDA will consider the following factors, among other things, in evaluating proposals:

1. The responsiveness of the proposed work program to the program regulations contained in 13 CFR 307.22;
2. The economic distress of the area served by the applicant;
3. Provision of an institutional capability statement, defining management and staff capacity and qualifications in economic program/policy development and operations;
4. Past performance of any currently funded grantee (including information in scheduled progress reports);
5. The local leaders' involvement in the applicants' economic development activities;
6. The amount of local participation provided as matching dollars to the Federal funds; and
7. Priority consideration will be given to currently funded grantees.

Proposal Submission Procedures

Application procedures may be obtained from EDA's regional offices for the following:

a. Currently funded planning grantees;

b. Proposals from applicants not currently funded under Categories A or B, that would fit into either of those categories; and

c. Special economic development activities that benefit one or more 301(b) grantees and cannot be financed with other resources.

Eligible applicants under both Categories A and B should submit proposals which include:

1. A letter signed by the chief elected official (Chairman of the Board, Tribal Chairman) or another authorized official of the applicant stating the organization's desire to receive funds to carry out the types of planning and administrative activities eligible under the 301(b) program.
2. Significant, verifiable information on the level of economic distress in the area, including unemployment and income data. Any major changes in distress levels during the past year should be described.
3. A work program outlining the specific development activities that will be carried out under the grant and explaining how they relate to the problems identified in the area CEDP, annual report, or other documents.

New applicants should submit one copy of the proposal to the appropriate economic development representative, and an original and one copy to the appropriate EDA regional office. Addresses of the EDA regional offices and listing of the economic development representatives are found in section X of this Notice.

Formal Application Procedures

EDA regional offices will contact currently funded grantees to inform them of the procedures for submitting applications for continuation funding.

Following review of the proposals submitted, EDA will invite those selected for funding consideration to submit formal applications. Funding levels will be determined by the economic distress and need of the area served by the applicants, past performance of previously funded grantees, and availability of program funds. The application will include an SF–424, as approved by the Office of Management and Budget Control No. 0348–0043.

Further Information

For further information contact the appropriate economic development representative, EDA regional office (see section X of this Notice), or the Director, Planning Division, Economic Development Administration, room 7321, U.S. Department of Commerce, Washington, DC 20230; telephone (202) 482–3027.

VII. Program: Planning Assistance for States and Urban Areas

(Catalog of Federal Domestic Assistance: 11.305 Economic Development—State and Urban Area Economic Development Planning)

Summary

Funds under the State and Urban Planning Program are awarded to defray administrative expenses in support of economic development planning efforts of eligible applicants. This program is authorized under section 302(a) of the Public Works and Economic Development Act of 1965, as amended, 42 U.S.C. 3151a.

Eligibility

Eligible applicants under this program are the governors of states, the chief executive officers of cities and counties, and substate planning and development organizations (including redevelopment areas and economic development districts).

Program Objective

The primary objective of planning assistance under section 302(a) is to support significant economic development planning and implementation initiatives of eligible applicants, particularly those experiencing severe economic distress.

Assistance must be part of a continuous process involving significant local leadership from public officials and private citizens and should include efforts to reduce unemployment and increase incomes. These efforts should be systematic and coordinated, when applicable, with planning organizations, and should strengthen the planning capabilities of applicants.

Planning program funds will not be used to provide support to activities that can be funded under the EDA Technical Assistance programs.

Activities eligible for support include economic analysis, definition of development goals, determination of project opportunities, development of economic development policies, processes and procedures, and formulation and implementation of a development program.

EDA is interested in proposals for planning activities designed to address problems of economically distressed segments of the population. Funding priority will be given to proposals promoting exports, entrepreneurship, and technology initiatives including innovation, transfer and commercialization, or that reduce barriers to the development of new businesses. In the case of proposals from states, EDA is particularly interested in innovative approaches to planning and implementing economic development initiatives, as well as efforts that lend themselves to replication in other areas.

Funding Availability

Funds in the amount of $4.516 million are available for providing grant assistance under this program.

Funding Instrument

Grant assistance may be provided for up to 75 percent of project costs. Applicants will be required to provide the remaining share, preferably in cash. Applications for grants exceeding $200,000 will be given low funding priority. EDA will consider proposals for smaller grants to support the aforementioned appropriate activities.

Project Duration

Assistance will be for the period of time required to complete the work. This period is normally 12 to 18 months. If Congress makes funds available for this program in subsequent years, grantees may submit applications for appropriate projects for up to a total of three awards.

Selection Criteria

The content of the proposal and the economic distress of the area will be the principal factors considered in evaluating proposals from eligible entities. In assessing the distress factor, priority consideration will be given to proposals from states and urban areas experiencing substantial economic distress. In the case of urban areas, high priority will be given to those with unemployment rates two or more percentage points higher than the U.S. average and per capita income levels 80 percent or less of the U.S. average. For states, high priority will be given to those that meet both of the above criteria, as well as those that meet one of the above criteria and have distress equal to or greater than the national level for the other criterion. The most recent per capita income and 24-month average unemployment data available will be used to measure economic distress.

Proposals from states or urban areas which do not exhibit significant distress on the basis of unemployment or income data will not be considered unless other acceptable evidence of substantial distress is provided by the applicant (e.g., large numbers of agricultural and business failures, large numbers of low income families, drastically reduced tax bases, etc.).

Proposals from states and urban areas which are both below the U.S. national unemployment rate and above the national per capita income are unlikely to be funded.

Proposals will be judged on the basis of:

1. Appropriateness of the work program to the section 302(a) program objectives;
2. The economic distress of the area served by the applicant;
3. Extent to which the proposed planning activities are expected to impact upon the service area's economic development needs, and the extent to which the proposal addresses the problems of the unemployed and underemployed of the area, including the farm families, minorities, workers displaced by plant closings, etc.;
4. Past performance of currently or formerly funded grantees, if applicable;
5. The amount of local participation provided as matching dollars to the Federal funds;
6. The proximity of the performing office to the chief executive (i.e., likelihood that the activities will have a significant influence on the policy and decision making process); and
7. Other characteristics, such as involvement of the private sector in the proposed activities, and particularly for states, the innovativeness of the proposed approach and replicability of the process or results.

Proposal Submission Procedures

Potential applicants should submit proposals that include:

1. A letter, signed by the chief executive of the applicant organization, indicating a desire to receive funds to carry out the planning activities outlined in the proposal; where the funded planning program will be placed in the organization, including the name and title of the person to be responsible for program implementation; the amount and for what period funding is being requested; and the anticipated funding arrangement if the planning activity is to continue beyond the period of EDA support.
2. Significant, verifiable information on the level of economic distress in the area, including unemployment and income data. Any major changes in distress levels during the past year should be described.
3. Information indicating the applicant's commitment to the proposed work program as demonstrated by amount of local funding and the degree of interest displayed by the chief executive.
4. A time chart showing all major work program elements, projected element start and completion dates, and the related financial expenditures programmed for each work element.
5. A work program of no more than 10 pages which outlines the specific planning activities that will be carried out under the grant and specifies which activities will be handled by in-house staff, consultants, etc. The work program should also explain the need for the proposed activities, expected impacts and their timing, target population(s), and involvement of the private sector in the proposed activities.

Current grantees seeking additional funding under this announcement should comply with the instructions of this notice and include a 3–5 page progress report for the current grant.

One copy of the proposal should be sent to the appropriate economic development representative, and an original and one copy to the appropriate EDA regional office. The EDA regional office or the name, address and telephone number of the economic development representative for the applicant's area can be found in section IX of this Notice.

Formal Application Procedures

EDA will evaluate proposals using the selection criteria cited above. Once the merits of the proposal are established, EDA will initiate discussions with the prospective applicant to clarify and improve elements of the proposal, if necessary, and will invite those whose proposals are selected for funding consideration to submit formal applications, which will include an SF–424 (OMB Control No. 0348–0043) and other application materials. It should be noted that an invitation to submit a proposal does not assure EDA funding. Proposals and applications will be processed as they are received. Applications received after FY 1993 funds are exhausted may be retained by EDA for consideration for funding the following fiscal year, assuming funds are available.

Further Information

For further information contact the appropriate economic development representative, EDA regional office (see section X of this Notice), or the Director, Planning Division, Economic Development Administration, room 7321, U.S. Department of Commerce, Washington, DC 20230; telephone (202) 482–3027.

VIII. Program: Economic Adjustment Assistance (Title IX)

(Catalog of Federal Domestic Assistance No: 11.307 Special Economic Development and Adjustment Assistance Program—Long-Term Economic Deterioration (LTED) and Sudden and Severe Economic Dislocation (SSED))

Summary

Funds under the Economic Adjustment Program are used to assist areas experiencing long-term economic

deterioration (LTED) and areas threatened or impacted by sudden and severe economic dislocation (SSED). This program is authorized under title IX of the Public Works and Economic Development Act of 1965, as amended, 42 U.S.C. 3241–3245.

Program Objective

The LTED Program assists eligible applicants to develop or implement strategies designed to halt and reverse the long-term decline of their economies. The most common type of activity funded under the LTED Program is Revolving Loan Funds (RLFs), although other types of eligible title IX activities may be funded.

The SSED Program assists eligible applicants to respond to actual or threatened major job losses (dislocations) and other severe economic adjustment problems. It is designed to help communities prevent a sudden, major job loss; to reestablish employment opportunities and facilitate community adjustment as quickly as possible after one occurs; or to meet special needs resulting from severe changes in economic conditions. SSED assistance is intended to respond to permanent rather than temporary job losses. Assistance may be in the form of a grant to develop a strategy to respond to the dislocation (Strategy Grant) or a grant to implement an EDA approved strategy (Implementation Grant).

In light of the current high level of economic distress in rural areas, EDA is particularly interested in title IX projects designed to mitigate serious rural economic adjustment problems. EDA is also interested in proposals to help severely distressed areas with large minority populations.

Funding Availability

Funds in the amount of $22.075 million are available for the Economic Adjustment Program in FY 1993. Of that amount, $11.038 million will be available for the SSED Program and $11.037 million will be available for the LTED Program.

Funding Instrument

Title IX funds are awarded through grants not to exceed 75 percent of the project cost. Acceptable sources of the local share include, but are not limited to, local government general revenue funds; Community Development Block Grant (CDBG) entitlement funds or balance of state awards; and other public and private donations. The Assistant Secretary may waive all or part of the 25 percent nonfederal share of economic adjustment assistance grants, if he/she determines that the nonfederal share is not reasonably available because of the critical nature of the situation requiring economic adjustment assistance or for other good cause. The full amount of the local share need not be in hand at the time of application; however, the applicant must have a firm commitment from identified source(s), and the funds must be readily available. The local share must not be encumbered in any way that would preclude its use as required by the grant agreement. The local share for the RLF Program must be in cash, and while the local share for the SSED Program may be cash or in-kind, priority consideration will be given to proposals with a cash local share.

Eligible Applicants

Eligible applicants within areas meeting the EDA eligibility criteria described below include a redevelopment area or economic development district established under title IV of this Act, 42 U.S.C. 3161; an Indian tribe; a state; a city or other political subdivision of a state, or a consortium of such political subdivisions; a Community Development Corporation defined in the Community Economic Development Act, 42 U.S.C. 9802; a nonprofit organization determined by EDA to be the representative of a redevelopment area; the Federated States of Micronesia, the Republic of the Marshall Islands, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands.

Eligible Areas

A. LTED

In order to receive priority consideration for funding under the LTED/RLF Program, an area must be experiencing at least one of three economic problems: Very high unemployment; low per capita income; or chronic distress (i.e., failure to keep pace with national economic growth trends over the last five years). Priority will be given to those areas with two or more of these indicators. Eligibility is determined statistically. Further information is available from EDA's regional offices or the economic development representative for your area (see Section X of this Notice).

B. SSED

In order to receive priority consideration for funding under the SSED Program, an area must show actual or threatened permanent job losses that exceed the following threshold criteria, unless otherwise determined by the Assistant Secretary:

1. For areas not in Metropolitan Statistical Areas:

a. If the unemployment rate of the Labor Market Area exceeds the national average, the dislocation must amount to the lesser of two (2.0) percent of the employed population, or 500 direct jobs.

b. If the unemployment rate of the Labor Market Area is equal to or less than the national average, the dislocation must amount to the lesser of four (4.0) percent of the employed population, or 1,000 direct jobs.

2. For areas within Metropolitan Statistical Areas:

a. If the unemployment rate of the Metropolitan Statistical Area exceeds the national average, the dislocation must amount to the lesser of one-half (0.5) percent of the employed population, or 4,000 direct jobs.

b. If the unemployment rate of the Metropolitan Statistical Area is equal to or less than the national average, the dislocation must amount to the lesser of one (1.0) percent of the employed population or 8,000 direct jobs.

In addition, fifty (50) percent of the job loss threshold must result from the action of a single employer, or eighty (80) percent of the job loss threshold must occur in a single standard industry classification (i.e., two digit SIC code).

In the case of a Presidentially declared natural disaster, the area eligibility criteria are waived. In other similarly exceptional circumstances, the criteria may be partially waived at the discretion of the Assistant Secretary.

Actual dislocations must have occurred within one year and threatened dislocations must be anticipated to occur within two years of the date EDA is contacted.

Selection Criteria

Proposals will be evaluated based on conformance with statutory and regulatory requirements, the economic adjustment needs of the area, the merits of the proposed project in addressing those needs and the potential applicant's ability to manage the grant effectively.

A. LTED/RLF Selection Criteria

Key factors in EDA's selection of proposed LTED/RLF projects include:

1. Economic and Financial Needs of the Project Area:

a. Areas with the highest levels of economic distress (high unemployment, low per capita income, vacant plants, deteriorating infrastructure, and declining farm economy, etc.) will receive priority consideration.

b. Need for RLF financing will be evaluated based on the local capital market and the applicant's analysis of it,

and how clearly this analysis defines the financial problems to be addressed by the RLF project.

c. Applicant's need for grant funds to carry out the project will be based on an assessment of its financial resources.

2. Objectives and Benefits of Proposed Projects:

Priority will be given to projects that:

a. Stimulate private sector employment. The number and types of jobs to be created/retained will be key factors in project selection along with the job/cost ratio established for the RLF portfolio as a whole.

b. Target assistance to meet program objectives and to support specific economic adjustment activities planned or underway in the area, particularly those identified in the OEDP, title IX strategy, or other plans developed to deal with specific economic adjustment problems affecting the area. This may include target areas, industries, types of employers or other criteria that maximize the impact of assistance on specific needs within the area.

c. Leverage higher ratios of private investment than the required minimum ratio of two private sector investment dollars to one RLF dollar.

Note: The local share or other funds provided by the RLF to finance loans cannot be counted as leveraged dollars.

d. Promote exports, entrepreneurship, and technology initiatives including innovation, transfer and commercialization.

e. Direct new job opportunities to the long-term unemployed and underemployed.

f. Provide technical and management assistance for RLF borrowers, in addition to loan funds.

g. Use creative financing techniques to overcome specific gaps in the local capital market.

h. Make loans on a timely basis. The implementation schedule for RLF projects will normally require that RLF loans in the initial round be closed (and all EDA funds disbursed) within three years of grant approval with no less than 50 percent disbursed within eighteen months and 80 percent within two years.

i. Include a larger local share than the required 25 percent or secure commitments for future funding from other private or nonfederal public sources.

j. Coordinate activities with other economic development organizations, loan programs, employment training programs and private lenders in the area.

k. Are established to fill capital gaps as opposed to providing subsidized credit (i.e., below market interest rates).

3. Effective Management of the RLF:

EDA will also evaluate proposed projects to determine that the RLF will be properly managed. Key factors include:

a. A strong and effective Loan Administration Board with broad community representation, including appropriate public and private sector representation.

b. Staff capacity in program and policy development, finance, law, marketing, credit analysis, loan packaging, processing, and servicing.

c. Efficient procedures for loan selection, approval, and servicing which emphasize the economic development potential of loans as well as sound management and financing practices.

d. A strategy for relending loan repayments which will ensure that the RLF revolves continuously and thus fulfills its purpose of creating jobs and stimulating economic activity on an ongoing basis.

e. Adequate resources to cover administrative costs of the RLF.

f. The potential applicant's experience and capacity for administering economic and business loan programs. If the potential applicant has designated another organization to administer the project, EDA will evaluate the experience and capacity of that organization, rather than the potential applicant.

Nongovernmental (excluding economic development districts) organizations seeking funds must be sponsored by the local or state government having jurisdiction over the project area, and the sponsor must be willing to assume responsibility for operating the RLF should the nongovernmental entity no longer be able to administer the project.

B. SSED Evaluation Criteria

Key factors in EDA's selection of proposed SSED projects include:

1. The severity of the dislocation as measured by, but not limited to, the following factors:

a. The degree to which the number of dislocated workers exceeds the eligibility threshold.

b. The proportion of the total job loss represented by a single employer.

c. The proportion of employment in a single standard industry classification represented by the firm(s) closing.

d. The applicant's need for grant funds to carry out the project based on an assessment of its financial resources.

2. The objectives and benefits of proposed activities as measured by the extent to which:

a. For Implementation Grants:

(1) Job creation or retention and restoration of the community's economic base in the near term are emphasized versus more long-term, general economic development. Projects likely to encounter delays, particularly in initiating or completing construction, will normally not be given favorable consideration.

(2) The jobs to be created or retained are permanent, will directly benefit the dislocated workers or will directly facilitate community adjustment, and are new employment opportunities and not transferred from one area of the United States to another.

(3) The response to the problem is timely.

(4) EDA assistance will be complemented by, or will complement, appropriate state and local efforts; for example, training and job placement services, other Federal investments, and private sector support.

(5) The adjustment strategy and implementation activities proposed demonstrate an appropriately creative approach to addressing the dislocation.

(6) The cost per job created or retained is minimized.

(7) In the case of a Revolving Loan Fund, the recycled loan proceeds generate economic development benefits.

(8) The local share exceeds the required 25 percent.

b. For Strategy Grants:

(1) The applicant has demonstrated the capacity to manage the planning process and subsequent implementation activities.

(2) The proposed scope of work is responsive to the problem.

(3) The focus of the planning effort is on the generation of practical and implementable solutions.

(4) The local share exceeds the required 25 percent.

Project Implementation

As indicated in the first section of this Notice, EDA expects all grant-funded projects to be initiated and completed in a timely manner in accordance with the schedule agreed upon in the grant documentation. The recipient will be responsible for promptly notifying EDA of any events that prevent adherence to the approved schedule. The grantee must also provide an explanation of why the events were beyond its ability to predict or control and obtain EDA approval of changes in the schedule prior to proceeding with project implementation.

EDA expects grantees to anticipate predictable delays (such as those caused by land acquisition problems, local financing requirements, acquisition of state permits and approvals, normal weather conditions in area, and public

objections to the project), and take them into account in preparing the project schedule. Grantees who fail to comply with project schedules may be subject to grant suspension or termination.

Proposal Submission Procedures

Interested parties should contact the economic development representative for the area or the appropriate EDA regional office (see section X of this Notice) for a proposal package. Project proposals, submitted by eligible entities, will be evaluated by EDA staff on the basis of:

1. Conformance with the evaluation criteria mentioned above and statutory, regulatory and policy requirements.
2. The availability of funds.

Application Procedures

Following a review of project proposals, EDA will invite those projects selected for funding consideration to submit applications. It should be noted that an invitation to apply does not assure funding. The application will include an ED–540, as approved by the Office of Management and Budget Control No. 0610–0058.

Further Information

For further information, contact the appropriate economic development representative, EDA regional office (see section X of this Notice), or the Director, Economic Adjustment Division, Economic Development Administration, room 7327, U.S. Department of Commerce, Washington, DC 20230; telephone (202) 482–2659.

IX. Program: Trade Adjustment Assistance

(Catalog of Federal Domestic Assistance: 11.313 Economic Development—Trade Adjustment Assistance)

Summary

Funds under the Trade Adjustment Assistance Program are awarded to a network of Trade Adjustment Assistance Centers, located around the Nation, which provide technical assistance to certified firms adversely affected by increased imports. Funds are also awarded under this program to organizations representing trade-injured industries. This program is authorized under the Trade Act of 1974, title II, Public Law 93–618, as amended, 88 Stat. 1978, 19 U.S.C. 2101–2487.

Funding Availability

Funds in the amount of $13.220 million are available for trade adjustment assistance to firms. These funds will be provided to the nationwide network of twelve (12) Trade Adjustment Assistance Centers (TAACs) through cooperative agreements which will utilize all of the available funds for trade adjustment assistance.

Therefore, no new centers will be funded in FY 1993. Funds in the amount of $500,000 are available for industry technical assistance.

Program Objective

The Trade Adjustment Assistance Program is designed to provide technical assistance to certified firms and industries hurt by the impact of increased imports. The TAACs help firms submit certification petitions to the Trade Adjustment Assistance Division (TAAD) of EDA, and if the firm is certified, provides technical assistance. A firm should work closely with the appropriate TAAC in petitioning for certification. Certified firms should also work closely with the appropriate TAAC in diagnosing their problems and developing an adjustment proposal, and in applying for technical assistance.

An industry association or other organization interested in receiving an industry assistance cooperative agreement must meet with a TAAD representative to discuss the industry's problems, opportunities, and assistance needs.

Criteria for Selecting Industry Assistance Proposals

Industry associations and other organizations seeking trade adjustment industry assistance must demonstrate that the industry is injured by foreign trade and that the activities to be funded will yield some short-term actions that the industry itself (and individual firms) can and will take toward the restoration of the industry's international competitiveness.

The emphasis is on practical results that can be implemented in the near term, and long-term research and development activities are given low priority. It is also expected that the industry will continue activities on its own without the need for continued Federal assistance.

Application Procedures

Industry associations or other organizations seeking industry assistance must submit an application identified as Standard Form 424 (OMB Control No. 0348–0043), if encouraged to do so as a result of the meeting with a TAAD representative.

Acceptable industry assistance applications will be processed as funds are available; normally one to three months is required for final decision on application.

Formula and Matching Requirements

Generally, a minimum of 50 percent share is required for industry assistance cooperative agreements.

Length and Time Phasing of Assistance

Industry assistance cooperative agreements are generally for a 12-month period, but may be longer for tasks requiring more time to complete.

Further Information

For further information, contact the Director, Trade Adjustment Assistance Division, Economic Development Administration, room 7023, U.S. Department of Commerce, Washington, DC 20230; telephone (202) 482–3373.

X. EDA Regional Offices and Economic Development Representatives

The EDA regional offices, states covered, and the economic development representatives (EDRs) are listed below.

EDRs	States covered
ATLANTA REGIONAL OFFICE	
401 West Peachtree Street, NW., suite 1820, Atlanta, Georgia 30308–3510, Telephone: (404) 730–3002	
Burnette, F. Wayne, Aronov Building, room 134, 474 South Court Street, Montgomery, AL 36104, Telephone: (205) 223–7008.	Alabama.
Day, William J. Jr., Federal Building, room 423, 80 North Hughey Avenue, Orlando, FL 32801, Telephone: (407) 648–6572.	Florida.
Smith, Lola B., 401 West Peachtree Street, NW., suite 1820, Atlanta, GA 30308–3510, Telephone: (404) 730–3000.	Georgia.
Hunter, Bobby D., 771 Corporate Drive, suite 200, Lexington, KY 40503–6477, Telephone: (606) 233–2596	Kentucky.

EDRs	States covered
Ainsworth, Bob, 221 Federal Building, 100 West Capital Street, Jackson, MS 39269, Telephone: (601) 965–4342.	Mississippi.
Jones, Dale L., P.O. Box 2522, Raleigh, NC 27601, Telephone: (919) 856–4570	North Carolina.
Dixon, Patricia M., Strom Thurmond Federal Building, 1835 Assembly Street, room 840, Columbia, SC 29201, Telephone: (803) 765–5676.	South Carolina.
Parks, Mitchell S., 261 Cumberland Bend Drive, Nashville, TN 37228, Telephone: (615) 736–5911	Tennessee.
AUSTIN REGIONAL OFFICE	
Suite 201, Grant Building, 611 East Sixth Street, Austin, Texas 78701–3748, Telephone: (512) 482–5461	
Spearman, Sam, room 2509, Federal Building, 700 West Capitol, Little Rock, AR 72201, Telephone: (501) 324–5637.	Arkansas.
Davidson, Pamela, 412 North Fourth Street, room 104, Baton Rouge, LA 70802–5523, Telephone: (504) 389–0227.	Louisiana.
Swearingen, James, P.O. Box 2662, Santa Fe, NM 87501, Telephone: (505) 988–6557	New Mexico.
Waters, Alvin X. Jr., 5500 North Western, suite 148, Oklahoma City, OK 73118–4011, Telephone: (405) 231–4197.	Oklahoma.
Ramirez, Roy, suite 201, Grant Building, 611 East Sixth Street, Austin, TX 78701–3748, Telephone: (512) 482–5118.	Texas (south).
Jacob, Lawrence, suite 201, Grant Building, 611 East Sixth Street, Austin, TX 78701–3748, Telephone: (512) 482–5119.	Texas (north).
CHICAGO REGIONAL OFFICE	
111 North Canal Street, suite 855, Chicago, IL 60606–7204, Telephone: (312) 353–7706	
Casals, Alfred L., 509 West Capitol, suite 204, Springfield, IL 62704, Telephone: (217) 492–4224	Illinois.
Henderson, Richard L., Federal Building Courthouse, room 402, 46 East Ohio Street, Indianapolis, IN 46204, Telephone: (317) 226–6104.	Indiana.
Collison, James L., 100 North Warren Avenue, room 1018, Saginaw, MI 48606–0867, Telephone: (517) 758–4097.	Michigan.
Arnold, John B. III, 104 Federal Building, 515 West First Street, Duluth, MN 55802, Telephone: (218) 720–5326.	Minnesota.
Hickey, Robert F., Federal Building, room 607, 200 North High Street, Columbus, Ohio 43214, Telephone: (614) 469–7314.	Ohio.
Price, Jack D., 505 South Dewey Street, room 202, Eau Claire, WI 54701, Telephone: (715) 834–4079	Wisconsin.
DENVER REGIONAL OFFICE	
1244 Speer Boulevard, room 670, Denver, Colorado 80204, Telephone: (303) 844–4714	
Zender, John, 1244 Speer Boulevard, room 632, Denver, CO 80204, Telephone: (303) 844–4902	Colorado, Kansas.
Cecil, Robert, Federal Building, room 593A, 210 Walnut Street, Des Moines, IA 50309, Telephone: (515) 284–4746.	Iowa.
Koch, Forrest E., Robert A. Young Building, room 8.308H, 1222 Spruce Street, St. Louis, MO 63103, Telephone: (314) 539–2321.	Missouri.
Rogers, John C., Federal Building, room 196, Drawer 10074, Helena, MT 59626, Telephone: (406) 449–5074	Montana.
Albertson, Warren A., Federal Building, room 219, Pierre, SD 57501, Telephone: (605) 224–8280	Nebraska, South Dakota.
Grant, Cornelius P., P.O. Box 1911, Bismarck, ND 58501, Telephone: (701) 250–4321	North Dakota.
Ockey, Jack, Federal Building, room 2414, 125 South State Street, Salt Lake City, UT 84138, Telephone: (801) 524–5119.	Utah, Wyoming.
PHILADELPHIA REGIONAL OFFICE	
Curtis Center, Independence Square West, suite 140 South, Philadelphia, PA 19106, Telephone: (215) 597–4603	
Hammarlund, C.N. Jr., Federal Office Building, room 453, 450 Main Street, Hartford, CT 06103, Telephone: (203) 240–3256.	Connecticut, Rhode Island.
Flynn, Patricia A., 2568 Riva Road, 2nd Floor, Annapolis, MD 21401, Telephone: (410) 962–2513	Delaware, Maryland, District of Columbia.
Blitz, Sandford, Federal Building, room 410D, 40 Western Avenue, Augusta, ME 04330, Telephone: (207) 622–8271.	Maine.
Fitzhenry, William A., Boston Federal Office Building, 10 Causeway Street, room 420 (Box 2), Boston, MA 02222–1036, Telephone: (617) 565–7235.	Massachusetts.
Potter, Rita, V., 143 North Main Street, suite 209, Concord, NH 03301, Telephone: (603) 225–1624	New Hampshire, Vermont.
Rossignol, Clifford J., 44 South Clinton Avenue, room 703, Trenton, NJ 08609, Telephone: (609) 989–2192	New Jersey.
Marshall, Harold J. II, 620 Erie Boulevard West, suite 104, Syracuse, NY 13204, Telephone: (315) 423–5203	New York.
Pecone, Anthony M., 1933A New Berwick Highway, Bloomsburg, PA 17815, Telephone: (717) 389–7560	Pennsylvania.
Cruz, Ernesto L., Federal Office Building, room 620, 150 Carlos Chardon Avenue, Hato Rey, PR 00918–1738, Telephone: (809) 766–5187.	Puerto Rico, Virgin Islands.
Noyes, Neal E., P.O. Box 10229, Richmond, VA 23240, Telephone: (804) 771–2061	Virginia.
Davis, R. Byron, Rose City Press Building, 550 Eagan Street, room 305, Charleston, WV 25301, Telephone: (304) 347–5252.	West Virginia.

EDRs	States covered
SEATTLE REGIONAL OFFICE	
Jackson Federal Building, room 1856, 915 Second Avenue, Seattle, Washington 98174, Telephone: (206) 553–0596	
Richert, Bernhard E. Jr., 605 West 4th Avenue, room G–80, Anchorage, AK 99501–7594, Telephone: (907) 271–2272.	Alaska.
Perot, C. Antony, Federal Building, room 3406, 230 North First Avenue, Phoenix, AZ 85025, Telephone: (602) 379–3750.	Arizona, Nevada (except Elko, Eureka and White Pine Counties).
Sosson, Deena R., 1345 J Street, suite B, Sacramento, CA 95814, Telephone: (916) 551–1541	California (northern).
Lewis, William J., 1345 J Street, suite , Sacramento, CA 95814, Telephone: (916) 551–2160	California (central).
Oaks, Charles W., 11000 Wilshire Boulevard, room 11105, Los Angeles, CA 90024, Telephone: (310) 575–7286	California (southern).
McChesney, Frank, P.O. Box 50264, Federal Building, room 4106, Honolulu, HI 96850, Telephone: (808) 541–3391.	Hawaii, Guam, American Samoa, Marshall Islands, Micronesia, Northern Marianas.
Ames, Aldred F., room 441, 304 North 8th Street, Boise, ID 83702, Telephone: (208) 334–1521	Idaho, Nevada (counties of Elko, Eureka & White Pine).
Berblinger, Anne S., One World Trade Center, 121 S.W. Salmon Street, suite 244, Portland, OR 97204, Telephone: (503) 326–3078.	Oregon.
Busch, Jay M., Jackson Federal Building, 915 Second Avenue, room 1856, Seattle, WA 98174, Telephone: (206) 553–4740.	Washington.

Dated: January 5, 1993.

L. Joyce Hampers,

Assistant Secretary for Economic Development.

[FR Doc. 93–475 Filed 1–8–93; 8:45 am]

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federal register

Monday
January 11, 1993

Part V

Department of Agriculture

Agricultural Marketing Service

7 CFR Part 52

U.S. Standards for Grades of Frozen Cauliflower; Proposed Rule

DEPARTMENT OF AGRICULTURE

Agriculture Marketing Service

7 CFR Part 52

[FV-91-329]

United States Standards for Grades of Frozen Cauliflower

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Proposed rule.

SUMMARY: The purpose of this proposed rule is to revise the current voluntary U.S. Standards for Grades of Frozen Cauliflower. The proposed rule was developed by the U.S. Department of Agriculture (USDA) at the request of the American Frozen Food Institute (AFFI) and the National Food Processors Association (NFPA). Its effect would be to improve the standards by: Bringing the standards in line with current marketing practices and innovations in processing techniques; providing for the "individual attributes" procedure for product grading with sample sizes, acceptable quality levels (AQL's), tolerances and acceptance numbers (number of allowable defects) being published in the standards; replacing dual grade nomenclature with single letter grade designations, such as "U.S. Grade A" or U.S. Fancy," with "U.S. Grade A;" and providing a uniform format consistent with other recently revised U.S. grade standards by adopting definitions for terms and replacing textual descriptions with easy-to-read tables. This proposed rule also includes conforming and editorial changes.

DATES: Comments must be received on or before March 12, 1993.

ADDRESSES: Interested persons are invited to submit written comments concerning this proposal. Comments must be sent in duplicate to the Office of the Branch Chief, Processed Products Branch, Fruit and Vegetable Division, Agricultural Marketing Service, U.S. Department of Agriculture, P.O. Box 96456, room 0709, South Building, Washington, DC 20090-6456. Comments should make reference to the date and page number of this issue of the Federal Register and will be made available for public inspection in the Office of the Branch Chief during regular business hours.

FOR FURTHER INFORMATION CONTACT: Randle A. Macon, Processed Products Branch, Fruit and Vegetable Division, Agricultural Marketing Service, U.S. Department of Agriculture, P.O. Box 96456, room 0709, South Building, Washington, DC 20090-6456, Telephone: (202) 720-6247.

SUPPLEMENTARY INFORMATION: This rule has been reviewed under USDA procedures, Executive Order 12291 and Departmental Regulation 1512-1 and has been designated as a "nonmajor" rule. It will not result in an annual effect on the economy of $100 million or more. There will be no major increase in cost or prices for consumers; individual industries; Federal, State, or local government agencies; or geographic regions. It will not result in significant effects on competition, employment, investments, productivity, innovations, or the ability of United States-based enterprises to compete with foreign-based enterprises in domestic or export markets.

This proposed rule has been reviewed under Executive Order 12778, Civil Justice Reform. This action is not intended to have retroactive effect. This proposed rule will not preempt any State or local laws, regulations, or policies, unless they present an irreconcilable conflict with this rule. There are no administrative procedures which must be exhausted prior to any judicial challenge to the provisions of this rule.

Agencies are required to periodically review existing regulations. An objective of the regulatory review is to ensure that the grade standards are serving their intended purpose, the language is clear, and the standards are consistent with AMS policy and authority.

The Department of Agriculture is committed to carrying out its statutory and regulatory mandates in a manner that best serves the public interest. Therefore, where legal discretion permits, the Department actively seeks to promulgate regulations that promote economic growth, create jobs, are minimally burdensome and are easy for the public to understand, use or comply with. In short, the Department is committed to issuing regulations that maximize net benefits to society and minimize costs imposed by those regulations. This principle is articulated in President Bush's January 28, 1992 memorandum to agency heads, and in Executive Orders 12291 and 12498. The Department applies this principle to the full extent possible, consistent with law.

The Department has developed and reviewed this regulatory proposal in accordance with these principles. Nonetheless, the Department believes that public input from all interested persons can be invaluable to ensuring that the final regulatory product is minimally burdensome and maximally efficient. Therefore, the Department specifically seeks comments and suggestions from the public regarding any less burdensome or more efficient alternative that would accomplish the purposes described in the proposal.

Comments suggesting less burdensome or more efficient alternatives should be addressed to the agency as provided in this Notice.

The Administrator, Agricultural Marketing Service, has certified that this action will not have a significant economic impact on a substantial number of small entities, as defined in the Regulatory Flexibility Act, Pub. L. 96-354 (5 U.S.C. 601 *et seq.*). The proposed changes reflect current marketing practices. The use of these standards is voluntary. A small entity may avoid incurring any economic impact by not employing the standards.

In 1988, the Western Technical Advisory Committee of the American Frozen Food Institute (AFFI), requested that the USDA prepare a draft revision of the U.S. grade standards for frozen cauliflower. This draft was to allow for the use of mechanical trimming devices in cauliflower processing by de-emphasizing the importance of uniform shape and symmetry of cauliflower clusters. Mechanical trimmers now perform processing operations previously done by hand. The mechanical trimming devices produce clusters which are less uniform in size, shape, and symmetry and remove, partially or completely, the bud portion of the unit. Shapes are "cosmetic" in nature and do not significantly affect the eating quality or nutritional value of frozen cauliflower.

It was also requested that the draft revision of the standards incorporate a grading system to make a better determination of quality. The grading system would assign individual tolerances to each individual quality factor. The system of grading, referred to as "individual attributes," would provide statistically derived acceptable quality levels (AQL's) based on the tolerances in the current grade standards. The USDA prepared a market survey, incorporating the requested changes and several other minor editorial changes.

USDA staff discussed this draft with the AFFI Western Technical Advisory Committee in January 1989. At that meeting, the USDA asked if other styles should be incorporated in the proposed standards. The Committee preferred to limit the styles as defined in the draft. No further comments were received. USDA then prepared another draft incorporating several minor editorial changes and submitted it to the AFFI

Western Technical Advisory Committee in February 1990. No comments were received.

In 1992, the USDA Grade Standards Review Subcommittee of the National Food Processors Association (NFPA), requested that the USDA prepare a draft revision of the U.S. grade standards for frozen cauliflower. It also requested that the draft revision of the standards incorporate the "individual attributes" grading system. The USDA prepared a draft revision and discussed it with the NFPA USDA Grade Standards Review Subcommittee in May 1992. The subcommittee recommended minor editorial changes for the draft standard.

The proposed standards would incorporate the recommended changes and USDA's policy of replacing dual grade nomenclature with single letter grade designations. Under the proposal, "U.S. Grade A" (or "U.S. Fancy") and "U.S. Grade B" (or "U.S. Extra Standard") would simply become "U.S. Grade A," and "U.S. Grade B."

In addition to these substantive changes, this proposed rulemaking would modify the standards so as to present them in a simplified easy-to-use format. Consistent with recent revisions of other U.S. grade standards, definitions of terms and easy-to-read tables would replace the textual descriptions. These changes are intended to facilitate better understanding and more uniform application of the grade standards.

List of Subjects in 7 CFR Part 52

Food grades and standards, Food labeling, Frozen foods, Fruit juices, Fruits, Reporting and recordkeeping requirements, Vegetables.

For the reasons set forth in the preamble, the U.S. Department of Agriculture proposes to amend 7 CFR part 52 as follows:

PART 52—PROCESSED FRUITS AND VEGETABLES, PROCESSED PRODUCTS THEREOF, AND CERTAIN OTHER PROCESSED FOOD PRODUCTS

1. The authority for part 52 continues to read as follows:

Authority: 7 U.S.C. 1622, 1624.

2. The Subpart—United States Standards for Grades of Frozen Cauliflower is revised to read as follows:

Subpart—United States Standards for Grades of Frozen Cauliflower

Sec.

52.721 Product description.
52.722 Styles.
52.723 Requirements for style.
52.724 Definitions of terms.
52.725 Grades.
52.726 Factors of quality.
52.727 Requirements for classified quality factors.
52.728 Sample size.
52.729 Acceptable criteria.

§ 52.721 Product description.

Frozen cauliflower is prepared from fresh flower heads of the cauliflower plant *(Brassica oleracea botrytis)* by trimming, washing, and blanching and is frozen and maintained at temperatures necessary for preservation of the product.

§ 52.722 Styles.

(a) *Clusters* mean individual segments of trimmed and cored cauliflower heads, which measure not less than 20 mm (0.75 in) in the greatest dimension across the top of the unit.

(b) *Clusters for limited use* mean individual segments of trimmed and cored cauliflower heads, which measure from 6 mm (0.25 in) to less than 20 mm (0.75 in) in the greatest dimension across the top of the unit.

§ 52.723 Requirements for style.

TABLE I.—AQL'S AND TOLERANCES (TOL.) FOR STYLE DEFECTS IN CLUSTERS, BASED ON 100 UNITS OF PRODUCTS FOR 13 SAMPLE UNITS, 100×13=1300 UNITS

	Clusters style	AQL	Tol.
Style defects	Each unit, less than 20 mm (0.75 in)	18.3	20.0

TABLE II.—ACCEPTANCE NUMBERS FOR STYLE DEFECTS IN CLUSTERS

Units of product	300	600	1300	2100	2900
Style defects [units less than 20 mm(0.75 in)]	66	125	261	414	565

TABLE III.—AQL'S AND TOLERANCES (TOL.) FOR STYLE DEFECTS IN CLUSTERS FOR LIMITED USE, 300 GRAMS OF PRODUCT FOR 13 SAMPLE UNITS, 300×13=3900 GRAMS

	Clusters for limited use style	AQL	Tol.
Style defects	20 mm (0.75 in) or greater	19.0	20.0
Style defects	Less than 6 mm (0.25 in)	9.2	10.0

TABLE IV.—ACCEPTANCE NUMBER FOR STYLE DEFECTS IN CLUSTERS FOR LIMITED USE

Grams of product	900	1800	3900	6300	8700
Style defects (grams) [units 20 mm (0.75 in) or greater]	190	369	781	1248	1713
Style defects (grams) [units less than 6 mm (0.25 in)]	98	187	390	618	847

§ 52.724 Definition of terms.

(a) *Acceptable quality level* (AQL) means the maximum percent of defective units or the maximum number of defects per hundred units of product that, for the purpose of acceptance sampling, can be considered satisfactory as a process average.

(b) *Blemished* means the cluster is affected or damaged by pathological injury, insect injury, discoloration or any other injury, which singly or in combination, affects the appearance or eating quality of the unit.

(1) *Minor* means a unit with a dark blemish exceeding the area of a circle 4 mm (0.16 in) in diameter but not exceeding 6 mm (0.25 in) or a light blemish exceeding the area of a circle 6 mm (0.25 in) in diameter.

(2) *Major* means a unit with a dark blemish exceeding the area of a circle 6 mm (0.25 in) in diameter.

(c) *Character* means the extent of firmness and compactness of the cluster and its degree of freedom from fuzzy, mushy, ricey and soft units.

(1) *Fuzzy character* means a cluster with elongated individual floral stems (petioles) that results in a fuzzy appearance.

(2) *Mushy character* means a cluster that is excessively soft or flabby and the flesh yields readily when handled.

(3) *Ricey character* means a cluster with elongated branches that result in a loose or granular appearance.

(4) *Soft character* means a cluster that is limp but not flabby.

(d) *Color defect* means that after cooking, the cluster possesses a color darker than light cream. The individual units may possess a characteristic green or bluish tint on the branches.

(e) *Core material* means the loose or attached center portion of the cauliflower head which is tough or fibrous.

(f) *Defect* means any nonconformance of a unit(s) of product from a specified requirement of a single quality characteristic.

(g) *Fragments* mean a stem or other cauliflower material without head material (exclusive of core material, loose leaves, and small pieces).

(h) *Loose leaves* mean leaf material, exclusive of small tender leaves, that is detached from the stem.

(i) *Mechanical damage* means that the appearance of the unit is seriously affected by excessive or insufficient trimming, or the unit is crushed or broken to the extent that the appearance is materially affected.

(j) *Normal flavor and order* means that the cauliflower, before or after cooking, has a flavor and odor that is normal and is free from objectionable flavors and odors.

(k) *Sample unit* means the amount of product specified to be used for grading. It may be:

(1) The entire contents of a container;

(2) A portion of the contents of a container;

(3) A combination of the contents of two or more containers.

(l) *Tolerance* (TOL.) means the maximum percent defective allowed, for each quality factor for a specific sample size, per defect.

(m) *Unit* means one cluster or piece of cauliflower.

§ 52.725 Grades.

(a) *U.S. Grade A* is the quality of frozen cauliflower that:

(1) Meets the following prerequisites in which the cauliflower:

(i) Has similar varietal characteristics; and

(ii) Has a normal flavor and odor.

(2) Is within the limits for defects as specified in Tables VI and VIII, as applicable for the style in § 52.727.

(b) *U.S. Grade B* is the quality of frozen cauliflower that:

(1) Meets the following prerequisites in which the cauliflower:

(i) Has similar varietal characteristics; and

(ii) Has a normal flavor and odor.

(2) Is within the limits for defects as specified in Tables VI and VIII, as applicable for the style in § 52.727.

(c) *Substandard* is the quality of frozen cauliflower that fails to meet the requirements of U.S. Grade B.

§ 52.726 Factors of quality.

The grade of frozen cauliflower is based on meeting the requirements for the following factors:

(a) Prerequisites;

(1) Varietal characteristics; and

(2) Flavor and odor.

(b) Classified quality factors;

(1) Blemished;

(2) Fuzzy character;

(3) Mushy character;

(4) Ricey character;

(5) Soft character;

(6) Color defects;

(7) Core material;

(8) Fragments;

(9) Loose leaves; and

(10) Mechanical damage.

§ 52.727 Requirements for classified quality factors.

TABLE V.—AQL'S AND TOLERANCES (TOL.) FOR DEFECTS IN CLUSTERS STYLE BASED ON 100 UNITS OF PRODUCT FOR 13 SAMPLE UNITS, 100×13=1300 UNITS

Defects	Grade A		Grade B	
	AQL	Tol.	AQL	Tol.
Blemished (major)	4.1	5.0	8.7	10.0
Total blemished (major & minor)	8.7	10.0	13.5	15.0
Fuzzy character	1.47	2.0	6.8	8.0
Mushy character	0.651	1.0	3.2	4.0
Ricey character	5.9	7.0	12.4	14.0
Soft character	8.7	10.0	12.5	14.0
Color defect	2.32	3.0	8.7	10.0
Core material	2.32	3.0	4.1	5.0
Fragments	6.0	6.0	13.5	15.0
Loose leaves	2.32	3.0	5.8	6.0
Mechanical damage	5.8	6.0	13.5	15.0

TABLE VI.—ACCEPTANCE NUMBERS FOR CLUSTERS STYLE

Units of product	Grade A					Grade B				
	300	600	1300	2100	2900	300	600	1300	2100	2900
Blemished (major)	18	33	65	101	137	34	64	130	205	278
Total blemished (major & minor)	34	64	130	205	278	50	94	195	309	421
Fuzzy character	8	14	26	40	53	28	51	104	162	220
Mushy character	4	7	13	20	26	15	26	52	80	106
Ricey character	24	48	91	142	192	46	87	180	285	389
Soft character	34	64	130	205	278	47	88	182	287	392
Color defect	11	20	39	60	81	34	64	130	205	278
Core material	11	20	39	60	81	18	33	65	101	137

TABLE VI.—ACCEPTANCE NUMBERS FOR CLUSTERS STYLE—Continued

Units of product	Grade A					Grade B				
	300	600	1300	2100	2900	300	600	1300	2100	2900
Fragments	28	51	104	162	220	50	94	195	309	421
Loose leaves (No. of leaves)	11	20	39	60	81	28	51	104	162	220
Mechanical damage	28	51	104	162	220	50	94	195	309	421

TABLE VII.—AQL'S AND TOLERANCES (TOL.) FOR DEFECTS IN CLUSTERS FOR LIMITED USE STYLE BASED ON 300 GRAMS OF PRODUCT FOR 13 SAMPLE UNITS, 300×13=3900 GRAMS

Defects	Grade A		Grade B	
	AQL	Tol.	AQL	Tol.
Blemished (major)	4.5	5.0	9.2	10.0
Total blemished (major & minor)	9.2	10.0	14.1	15.0
Fuzzy character	1.67	2.0	7.3	8.0
Mushy character	0.774	1.0	3.5	4.0
Ricey character	6.3	7.0	13.1	14.0
Soft character	9.2	10.0	13.1	14.0
Color defect	4.5	5.0	9.2	10.0
Core material	2.8	3.0	4.5	5.0
Fragments	14.1	15.0	24.9	26.0
Loose leaves	2.8	3.0	7.3	8.0
Mechanical damage	7.3	8.0	14.1	15.0

TABLE VIII.—ACCEPTANCE NUMBERS FOR DEFECTS IN CLUSTERS FOR LIMITED USE STYLE

Grams of product	Grade A					Grade B				
	900	1800	3900	6300	8700	900	1800	3900	6300	8700
Blemished (Grams) (Major)	51	96	197	311	424	98	187	390	619	847
Total blemished (grams) (major & minor)	98	187	390	619	847	144	278	586	934	1280
Fuzzy character (grams)	21	39	78	122	165	79	150	312	495	677
Mushy character (grams)	11	20	39	60	81	41	78	156	245	333
Ricey character (grams)	69	131	271	430	587	134	259	546	869	1192
Soft character (grams)	98	187	390	619	847	134	259	546	869	1192
Color defect (grams)	51	96	197	311	424	98	187	390	619	847
Core material (grams)	31	50	118	185	251	51	96	197	311	424
Fragments (grams)	144	278	586	934	1280	245	478	1015	1625	2233
Loose leaves (No. of leaves)	31	58	118	185	251	79	150	312	495	677
Mechanical damage (grams)	79	150	312	495	677	144	278	586	934	1280

§ 52.728 Sample size.

The sample size used to determine whether the requirements of these standards are met shall be as specified in the sampling plans and procedures in the "Regulations Governing Inspection and Certification of Processed Fruits and Vegetables, Processed Products Thereof, and Certain Other Processed Products" (7 CFR 52.1 through 52.83).

§ 52.729 Acceptance criteria.

(a) *Style.* A lot of frozen cauliflower clusters, is considered as meeting the requirements for style if the acceptance numbers in Table II or IV in § 52.723, as applicable, are not exceeded.

(b) *Quality Factors.* A lot of frozen cauliflower is considered as meeting the requirements for quality if:

(1) The prerequisites specified in § 52.726 are met; and

(2) The Acceptance Numbers in Table VI or VIII in § 52.727, as applicable, are not exceeded.

(c) *Single Sample Unit.* Each unofficial sample unit submitted for quality evaluation will be treated individually and is considered as meeting requirements for quality and style if:

(1) The prerequisites specified in § 52.726 are met; and

(2) The Acceptable Quality Levels (AQL's) in Tables I, III, V & VII in §§ 52.723 and 52.727, as applicable, are not exceeded.

Dated: December 31, 1992.

Daniel Haley,

Administrator

[FR Doc. 93–521 Filed 1–8–93; 8:45 am]

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federal register

Monday
January 11, 1993

Part VI

Department of Labor

Office of the Secretary

29 CFR Part 18

Use of Settlement Judges in Proceedings Before the Office of Administrative Law Judges; Proposed Rule

DEPARTMENT OF LABOR

Office of the Secretary

29 CFR Part 18

RIN 1290–AA12

Use of Settlement Judges in Proceedings Before the Office of Administrative Law Judges

AGENCY: Office of the Secretary, Labor.

ACTION: Notice of proposed rulemaking.

SUMMARY: The purpose of this proposal is to permit the appointment of settlement judges in proceedings before the Office of Administrative Law Judges. The procedure would use informal conferences to encourage claim settlement without adjudication. This is a voluntary procedure intended to reduce the costs to parties of filing and defending complaints and to expedite the resolution of complaints pursuant to Executive Order No. 12778 (Oct. 23, 1991) and the Department of Labor's Alternative Dispute Resolution Interim Policy, 57 FR 7292 (1992).

DATES: Comments must be received on or before February 25, 1993.

ADDRESSES: Submit comments to John M. Vittone, Deputy Chief Administrative Law Judge, room 4150, Office of Administrative Law Judges, 800 K Street, NW., suite 400, Washington, DC 20001–8002.

FOR FURTHER INFORMATION CONTACT: John M. Vittone, Deputy Chief Administrative Law Judge, Office of Administrative Law Judges. Telephone: (202) 633–0341.

SUPPLEMENTARY INFORMATION: In furtherance of its Alternative Dispute Resolution Interim Policy, 57 FR 7292 (1992), the Department is studying and implementing alternative dispute resolution methods appropriate to agency adjudications. This rule proposes use of settlement judges in certain proceedings before the Office of Administrative Law Judges. It is modeled on Recommendation 88–5 of the Administrative Conference of the United States, 1 CFR 305.88–5, and the settlement judge procedures of other agencies. See 18 CFR 385.603 (FERC); 24 CFR 104.620 (HUD); 29 CFR 2200.101 (OSHRC); 47 CFR 1.244 (FCC); 48 CFR 6302.30 (DOT). The procedure supplements rather than supplants settlement techniques traditionally used by administrative law judges. See, e.g., 29 CFR 18.8 (discussion of negotiation, compromise or settlement at prehearing conferences); 29 CFR 18.9 (deferment of hearing for settlement negotiations by the parties). It is expected that the Office of Administrative Law Judges would train a group of judges in mediation techniques. This group would be the pool from which settlement judges would be chosen.

The regulation permits appointment of a settlement judge by the Chief Administrative Law Judge upon motion by the parties or the presiding judge. Any party could veto use of the procedure. The settlement judge would be an active or retired administrative law judge other than the presiding judge. The settlement judge would direct settlement negotiations, assess the relative merits of the case for the parties, and consult with the parties either jointly or individually. The duration of the procedure would be limited because it is meant to quicken rather than delay dispute resolution, and because an exigent hearing motivates serious negotiation. The settlement judge would be prohibited from discussing any aspect of the case with the presiding judge. Any statements or conduct by the parties or the settlement judge at settlement negotiations would not be admissible in later proceedings before the Department.

Settlement judges would not be available in Black Lung or Longshore cases. The Benefits Review Board has found that the Black Lung Benefits Reform Act prohibits settlements. *See Gerzarowski* v. *Lehigh Valley Anthracite, Inc.*, 12 BLR 1–62 (1988); *Ladigan* v. *Central Industries, Inc.*, 7 BLR 1–192 (1984). Even without the prohibition, settlement judge procedures are not appropriate where entitlement to a benefit is an all-or-nothing question, as in Black Lung cases, since a settlement judge could do nothing except convince one party to concede.

Longshore cases are often settled; but neither the Department nor the public would benefit from a formal settlement judge procedure. The Longshore bar is comfortable with techniques used by the Office of Administrative Law Judges for many years, such as early prehearing exchanges, calendar calls in which settlement possibilities are discussed; and opportunities for discussion immediately prior to a hearing. See Notice of *Amendment to Interim ADR Policy*, 57 FR 28701, 28702–3 (June 26, 1992). See also Joseph & Gilbert, Breaking the Settlement Ice: The Use of Settlement Judges in Administrative Proceedings 2 Administrative L.J. 571, 594–595 (1989/1990) (indicating that if large numbers of cases are currently settled without the use of settlement judges, imposing the procedure is not advised).

Procedural Matters

This is not a major rule as defined by Executive Order 12291. The Agency Head has certified that this rule, if promulgated, will not have a significant economic impact upon a substantial number of small entities as defined in the Regulatory Flexibility Act (5 U.S.C. 601 et seq.). The rule does not contain any information collection or recordkeeping requirements as defined in the Paperwork Reduction Act of 1980 (44 U.S.C. 3501 et seq.).

List of Subjects in 29 CFR Part 18

Administrative practice and procedure.

Accordingly, part 18 of title 29 of the Code of Federal Regulations is proposed to be amended as follows:

PART 18—RULES OF PRACTICE AND PROCEDURE FOR ADMINISTRATIVE HEARINGS BEFORE THE OFFICE OF ADMINISTRATIVE LAW JUDGES

1. The authority citation for part 18 is revised to read:

Authority: 5 U.S.C. 301; 5 U.S.C. 551–553; 5 U.S.C. 581; E.O. 12778; 57 Fed. Reg. 7292.

2. Section 18.9 is amended by revising the section heading and by adding new paragraph (e) to read as follows:

§ 18.9 Consent order or settlement; settlement judge procedure.

* * * * *

(e)(1) *Settlement judge procedure; purpose.* This paragraph establishes a voluntary process whereby the parties may use a settlement judge to mediate settlement negotiations. A settlement judge is an active or retired administrative law judge who convenes and presides over settlement conferences and negotiations, confers with the parties both jointly and individually, and seeks voluntary resolution of issues. Unlike a presiding judge, a settlement judge does not render a formal judgment or decision in the case; his or her role is solely to facilitate fair and equitable solutions and to provide an assessment of the relative merits of the respective positions of the parties.

(2) *How initiated.* A settlement judge may be appointed by the Chief Administrative Law Judge upon a request by a party or the presiding administrative law judge. The Chief Administrative Law Judge has sole discretion to decide whether to appoint a settlement judge, except that a settlement judge shall not be appointed where—

(i) A party objects to referral of the matter to a settlement judge;

(ii) Such appointment is inconsistent with a statute, executive order, or regulation;

(iii) The proceeding arises pursuant to the Longshore and Harbor Workers' Compensation Act, 33 U.S.C. 901 et seq., and associated acts such as the District of Columbia Workmen's Compensation Act, 36 DC Code 501 et seq.; or

(iv) The proceeding arises pursuant to Title IV of the Federal Mine Safety and Health Act, 30 U.S.C. 901 et seq., also known as the Black Lung Benefits Act.

(3) *Selection of settlement judge.* The selection of a settlement judge is at the sole discretion of the Chief Administrative Law Judge, provided that the individual selected

(i) Is an active or retired administrative law judge, and

(ii) Is not the administrative law judge assigned to hear and decide the case. The settlement judge shall not be appointed to hear and decide the case.

(4) *Duration of proceeding.* Unless the Chief Administrative Law Judge directs otherwise, settlement negotiations under this section shall not exceed thirty days from the date of appointment of the settlement judge, except that with the consent of the parties, the settlement judge may request an extension from the Chief Administrative Law Judge. The negotiations will be terminated immediately if a party unambiguously indicates that it no longer wishes to participate, or if in the judgment of the settlement judge, further negotiations would be fruitless.

(5) *General powers of the settlement judge.* The settlement judge has the power to convene settlement conferences; to require that parties, or representatives of the parties having the authority to settle, participate in conferences; and to impose other reasonable requirements of the parties to expedite an amicable resolution of the case, provided that all such powers shall terminate immediately if negotiations are terminated pursuant to paragraph (e)(4).

(6) *Suspension of discovery.* Requests for suspension of discovery during the settlement negotiations shall be directed to the presiding administrative law judge who shall have sole discretion in granting or denying such requests.

(7) *Settlement conference.* In general the settlement judge should communicate with the parties by telephone conference call. The settlement judge may, however, schedule a personal conference with the parties where:

(i) A conference may be scheduled in a place and on a day that the settlement judge is scheduled to preside in other proceedings;

(ii) The offices of the attorneys or other representatives of the parties, and the settlement judge, are in the same metropolitan area; or

(iii) The settlement judge, with the concurrence of the Chief Administrative Law Judge, determines that a personal meeting is necessary for a resolution of substantial issues, and represents a prudent use of resources.

(8) *Confidentiality of settlement discussions.* All discussions between the parties and the settlement judge shall be off-the-record. No evidence regarding statements or conduct in the proceedings under this section is admissible in the instant proceeding or any subsequent administrative proceeding, except by stipulation of the parties. Documents disclosed in the settlement process may not be used in litigation unless obtained through appropriate discovery or subpoena. The settlement judge shall not discuss any aspect of the case with any administrative law judge or other person, nor be subpoenaed or called as a witness in any hearing of the case or any subsequent administrative proceedings with respect to any statement or conduct during the settlement discussions.

(9) *Contents of consent order or settlement agreement.* Any agreement disposing of all or part of the proceeding shall be written and signed by all parties. Such agreement shall conform to the requirements of paragraph (b) of this section.

(10) *Report of the settlement.* The parties shall report to the presiding judge in writing within seven working days of the termination of negotiations. The report shall include a copy of the settlement agreement and/or proposed consent order.

(11) *Review of agreement by presiding judge.* A settlement agreement arrived at with the help of a settlement judge shall be treated by the presiding judge as would be any other settlement agreement.

(12) *Non-reviewable decisions.* Decisions concerning whether a settlement judge should be appointed, the selection of a particular settlement judge, or the termination of proceedings under this section, are not subject to review by Department officials.

Signed at Washington, DC this 5th day of January, 1993.

Lynn Martin,

Secretary of Labor.

[FR Doc. 93–536 Filed 1–8–93; 8:45 am]

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CFR CHECKLIST

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An asterisk (*) precedes each entry that has been issued since last week and which is now available for sale at the Government Printing Office.

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Title	Stock Number	Price	Revision Date
1, 2 (2 Reserved)	(869–017–00001–9)	$13.00	Jan. 1, 1992
3 (1991 Compilation and Parts 100 and 101)	(869–017–00002–7)	17.00	[1] Jan. 1, 1992
4	(869–017–00003–5)	16.00	Jan. 1, 1992
5 Parts:			
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700–1199	(869–017–00005–1)	14.00	Jan. 1, 1992
1200–End, 6 (6 Reserved)	(869–017–00006–0)	19.00	Jan. 1, 1992
7 Parts:			
0–26	(869–017–00007–8)	17.00	Jan. 1, 1992
27–45	(869–017–00008–6)	12.00	Jan. 1, 1992
46–51	(869–017–00009–4)	18.00	Jan. 1, 1992
52	(869–017–00010–8)	24.00	Jan. 1, 1992
53–209	(869–017–00011–6)	19.00	Jan. 1, 1992
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2000–End	(869–017–00025–6)	11.00	Jan. 1, 1992
8	(869–017–00026–4)	17.00	Jan. 1, 1992
9 Parts:			
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10 Parts:			
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11	(869–017–00034–5)	12.00	Jan. 1, 1992
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[1] Because Title 3 is an annual compilation, this volume and all previous volumes should be retained as a permanent reference source.

[2] The July 1, 1985 edition of 32 CFR Parts 1–189 contains a note only for Parts 1–39 inclusive. For the full text of the Defense Acquisition Regulations in Parts 1–39, consult the three CFR volumes issued as of July 1, 1984, containing those parts.

[3] The July 1, 1985 edition of 41 CFR Chapters 1–100 contains a note only for Chapters 1 to 49 inclusive. For the full text of procurement regulations in Chapters 1 to 49, consult the eleven CFR volumes issued as of July 1, 1984 containing those chapters.

[4] No amendments to this volume were promulgated during the period Jan. 1, 1987 to Dec. 31, 1991. The CFR volume issued January 1, 1987, should be retained.

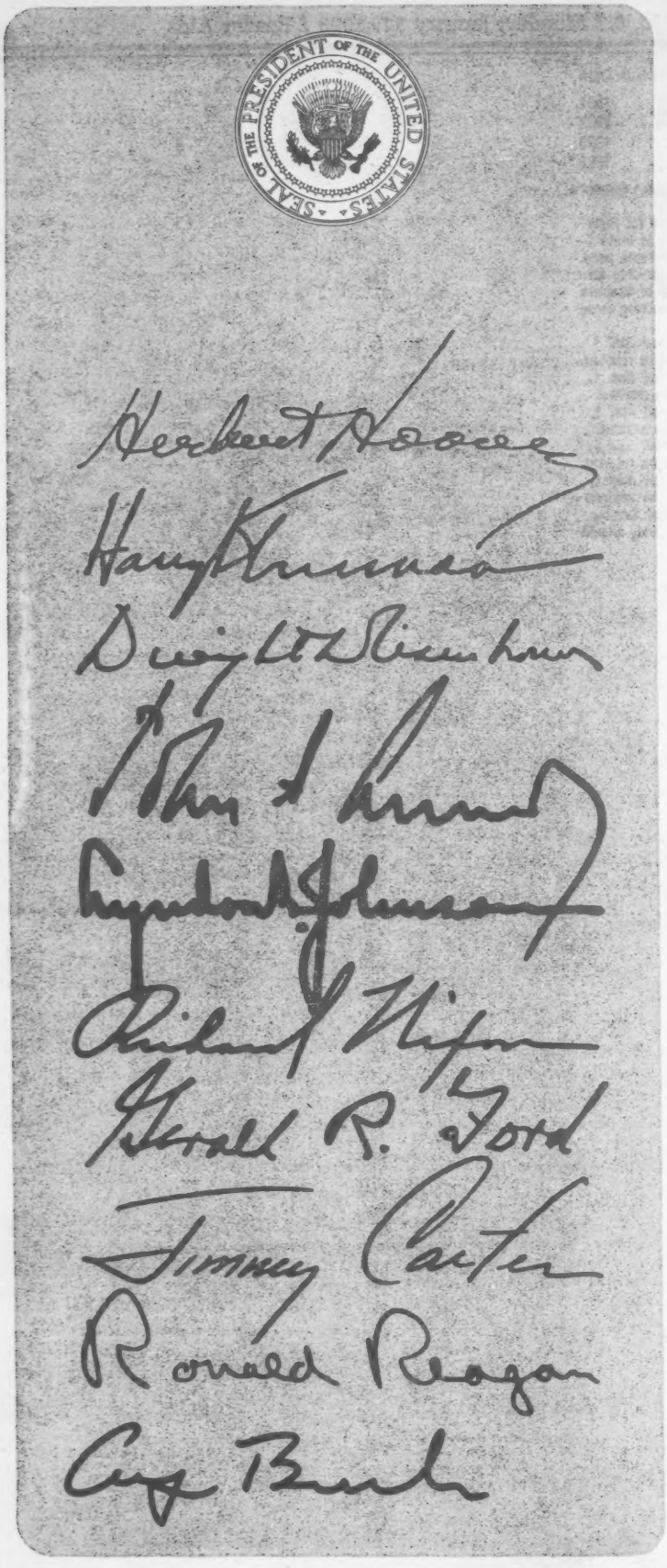
[5] No amendments to this volume were promulgated during the period Apr. 1, 1990 to Mar. 31, 1991. The CFR volume issued April 1, 1990, should be retained.

[6] No amendments to this volume were promulgated during the period Apr. 1, 1991 to Mar. 30, 1992. The CFR volume issued April 1, 1991, should be retained.

[7] No amendments to this volume were promulgated during the period July 1, 1989 to June 30, 1992. The CFR volume issued July 1, 1989, should be retained.

[8] No amendments to this volume were promulgated during the period July 1, 1991 to June 30, 1992. The CFR volume issued July 1, 1991, should be retained.

[9] No amendments to this volume were promulgated during the period October 1, 1991 to September 30, 1992. The CFR volume issued October 1, 1991, should be retained.



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